I. EXECUTIVE SUMMARY

Background and Major Findings

On February 23, 2004, the Joint Standing Committee on Utilities and Energy sent a letter to the Public Utilities Commission directing the Commission to examine the practices of Maine's transmission and distribution (T&D) utilities that affect the safety and reliability of the electric grid. This report presents the Commission's findings and recommendations.

In most respects, the Commission found that the utilities are adequately operating and maintaining the grid. In certain respects, however, our examination revealed signs of potential shortcomings that warrant further and more in-depth review. In particular, certain aspects of Central Maine Power Company's (CMP's) distribution system and operation and maintenance practices should be examined. Unlike Bangor Hydro-Electric Company (BHE) and Maine Public Service Company (MPS), CMP has for the last 10 years been operating within an Alternative Rate Plan (ARP)[1] with specified performance incentives. In addition, unlike BHE and MPS, CMP has not in recent years been subject to a thorough review of its distribution O&M standards and procedures.

While CMP has done a good job meeting the ARP's performance measures, there is a need to determine the effectiveness of those measures in ensuring the maintenance of an electric utility's distribution plant. Thus, an examination would not only shed light on CMP's maintenance practices but also might provide some indication of the efficacy of the Commission's performance standards. Such an examination would be especially timely with CMP's ARP expiring in 2007. For these reasons, CMP and the Commission have jointly agreed to have an independent review of CMP's distribution system as well as of its distribution maintenance practices and procedures.

The Reliability of the Distribution and Local Transmission System

Two indicators form the basis for measuring overall system reliability. SAIFI, or System Average Interruption Frequency Index, measures average frequency of sustained interruptions and is a good indicator of the condition of a utility's plant and the quality of a utility's maintenance activities. CAIDI, or Customer Average Interruption Duration Index, represents the average time required to restore service and is a good indicator of the quality of a utility's response to outages. SAIFI and CAIDI are measured on a company-wide average basis as part of CMP's and BHE's ARPs. Under the terms of their respective ARPs, both CMP and BHE are subject to financial penalties should

[1] Under the terms of an ARP, a utility's rates are adjusted annually based on changes to an external index and not based on changes in costs used as part of traditional "cost plus" regulation.

their annual SAIFI or CAIDI levels deteriorate and fall below pre-established standards.[2] Because it is possible to obtain reasonable indicators on this basis while performing poorly in specific areas, particularly those that are less densely populated, the Commission reviewed performance on the utilities' worst performing circuits. In addition, because SAIFI and CAIDI indicate current performance but cannot determine whether that performance will prevail in the future, the Commission reviewed the utilities' maintenance and inspection programs, capital and maintenance spending, vegetation management programs, and planning criteria.

The Commission found that CMP, and to a lesser extent BHE, have focused on meeting company-wide average targets required by their Alternative Rate Plans (ARPs) to the potential detriment of service in less densely populated areas. The Commission will continue to monitor the performance of BHE and CMP in these areas. We will also direct these utilities to address this issue in the next round of ARP proceedings. In addition, the Commission will closely monitor the utilities' inspection programs, which were not, until recently, in full compliance with the National Electric Safety Code (NESC).

Finally, CMP and the Commission have agreed, based on the issues that have arisen out of this study, that an additional examination of CMP's distribution system should be conducted by an independent consultant to review and assess CMP's current distribution plant as well as its distribution maintenance practices and procedures.

Central Maine Power Company (CMP) Findings

- CMP's planning, design and operation of its transmission plant are consistent with sound utility practices, allow CMP to detect problems that could degrade reliability, and are compliant with New England Independent System Operator (ISO-NE) and Northeast Power Coordinating Council (NPCC) requirements.

- Capital and O&M spending on transmission plant appear to be reasonable.

- Transmission vegetation management procedures are consistent with sound utility practices and are within NPCC and Federal Energy Regulatory Commission (FERC) recommendations.

- CMP's transmission inspection program is consistent with sound utility practice and meets all National Electric Safety Code (NESC), NPCC, and FERC requirements.

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[2] For both the CAIDI and SAIFI metrics, an increase in the indices represents a deterioration or worsening in performance.

- CMP's company-wide distribution CAIDI and SAIFI performances have increased in recent years. This may be due, in part, to better reporting.

- The Commission is concerned that CMP's worst performing distribution circuits are significantly worse than company-wide performance and are located almost entirely within less densely populated areas; that CMP has not reported these circuits in its annual report to the Commission; and that service on these circuits may have deteriorated in recent years.

- The Commission is concerned that outages have increased and the increases appear to occur in less densely populated areas.

- Capital and O&M spending for distribution raise no concerns.

- The Commission is concerned that CMP's distribution vegetation management procedures are primarily reactive, targeting areas only after a service reliability problem exists.

- For the past five years, CMP's distribution line inspection program has been informal, with no tracking of areas that have been inspected or worked on to resolve problems as a result of identified safety issues. The Commission believes that CMP's program did not meet NESC requirements. CMP has revised its program and the current program now appears to satisfy NESC requirements. The Commission is concerned, however, that a substantial time period will elapse before CMP can formally inspect all its circuits under its new program.

- Distribution plant age has increased in recent years. This raises concern when combined with the lack of an official inspection program and flat spending on distribution maintenance.

- CMP's improvement program raises concern because CMP does not track the capacity or safety margin on its circuits. The Commission is concerned that CMP improves circuits based primarily on contribution to company-wide SAIFI and may be sacrificing service quality in less densely populated areas.

In its comments on the Commission's Draft Report, CMP stated its belief that its past and current inspection procedures, vegetation management procedures, and record-keeping practices are adequate, and that it has been addressing reliability issues on its rural circuits. However, to address the concerns of the Commission cited above, and to resolve any misunderstandings concerning CMP's actual distribution practices and procedures, the Commission and CMP have agreed to have a more extensive study of CMP's distribution system conducted by an independent party. As part of this study, the condition of CMP's plant will be assessed and CMP's distribution practices and procedures will be reviewed.

Bangor Hydro-Electric Company (BHE) Findings

- BHE's planning, design and operation of its transmission plant are consistent with sound industry practices, allow BHE to detect problems that could degrade reliability, and are compliant with ISO-NE and NPCC requirements. On its own initiative, BHE recently conducted a 10-year transmission planning study and maintains clear documentation on its practices. BHE has proposed upgrades to certain transmission lines that will improve reliability.

- Capital and O&M spending on transmission plant are reasonable.

- Transmission vegetation management procedures are reasonable.

- BHE's transmission inspection and preventative maintenance programs are consistent with sound utility practice and meet all NESC requirements.

- BHE's company-wide distribution CAIDI and SAIFI performance have deteriorated steadily, which may in part be due to better record keeping. BHE's worst performing distribution circuits show less disparity from the company-wide average than do CMP's, but their service quality performance metrics have trended downward. This is of concern and the Commission will monitor the trend.

- The Commission is concerned that outages have increased.

- BHE recently improved its distribution vegetation management procedures by increasing the amount of area worked and decreasing costs.

- Capital spending for distribution has increased while maintenance expense has declined. It appears BHE has been able to achieve these reductions at least in part, as a result of improved efficiencies.

- Distribution plant age remains steady and raises no concern at this time.

- BHE recently submitted a new comprehensive line inspection program, which incorporates periodic testing and meets NESC requirements for inspection and data retention.

In summary, the Commission found some areas of concern that we will continue to monitor, although in many respects, BHE management has begun to resolve these on its own. BHE has decreased costs while attempting to improve service quality. Although BHE's indicators have deteriorated, improved record keeping may account for the trend. BHE has implemented improvements in a variety of areas, and has recently submitted a revised comprehensive inspection program.

Maine Public Service Company (MPS) Findings

- MPS's capital and O&M spending on transmission plant are reasonable.

- MPS's transmission inspection program is reasonable and meets NESC requirements.

- MPS's transmission vegetation management program is reasonable. However, there are locations in which MPS cannot obtain easements which may be resulting in tree-related reliability problems. MPS should more actively pursue securing easements.

- MPS's company-wide distribution CAIDI and SAIFI performances compare favorably with those of CMP and BHE, but they have recently deteriorated. MPS should monitor this situation.

- MPS's worst performing distribution circuits show less disparity from the company-wide average than do CMP's or BHE's, indicating that it is not focusing on maintaining reliability in populated areas at the expense of less populated areas.

- MPS's weather-related outages have increased steadily in recent years. This is likely a result of MPS's prior vegetation management program which MPS has revised in response to an internal investigation.

- MPS has redesigned its vegetation management program. While it appears reasonable, MPS's records do not allow assessment of cost-effectiveness.

- Capital spending for distribution has increased to catch up on deferred capital improvements. Distribution pole age is high, which raises concern about the condition of distribution plant. O&M expenses are reasonable.

- MPS recently improved its line inspection program. The new program meets NESC requirements and will help MPS improve reliability and address concerns regarding plant condition.

- On its own initiative, MPS recently retained a firm to assess the condition and performance of its system. MPS has addressed immediate safety issues and has adopted many of the recommendations regarding grid O&M.

In summary, as a result of a consultant's inspection, MPS recently implemented improvements in a variety of areas that should address concerns that the Commission encountered during this study. In other regards, MPS's practices are reasonable.

Eastern Maine Electric Cooperative (EMEC) Findings

- The Rural Utility Service (RUS) regularly evaluates EMEC's conformance to RUS standards. Most recently, RUS rated EMEC as satisfactory in all areas except service interruptions, and that category received a rating that was an improvement over the previous rating. Considering EMEC's rural nature, no major concerns exist regarding its grid management.

- EMEC's distribution circuit inspections do not fully comply with the NESC and should be revised accordingly. EMEC could improve its vegetation management program and should examine the causes of its substation outages. Finally, EMEC should be proactive in MPS's transmission planning as it regards the line supplying EMEC's power.

The Reliability of the Bulk Power Transmission Grid Administered by ISO-NE

The above sections related to the local T&D systems in Maine. Because Maine is part of a much larger electric grid, we also examined the entities and systems that affect the reliability of the interstate, high voltage, "bulk power" system.

The New England Independent System Operator (ISO-NE) is primarily responsible for the operation of the bulk power supply system in New England. Recently in New England, tight supply conditions have occurred during peak summer hours. In winter months, the price and availability of natural gas impacts the price and availability of electricity because a significant number of electricity generators depend upon natural gas for fuel production. Maine has more in-state generating capacity than necessary to meet its load. Coupled with transmission limits on exports, this excess capacity places Maine in a good position in terms of reliability and price. That said, even in Maine, electricity prices are very much affected by fossil fuel prices.

ISO-NE communicates with all relevant local entities, including government and emergency response agencies, on a regular schedule and more often when the system is stressed. In addition, operating procedures are in place to address shortages.

Recent bulk power events include:

- **Northeast blackout of August 2003**. New England and the Maritimes isolated from the rest of the system, but voltages were depressed in some locations and one Maine customer disconnected from the grid. NEPOOL's system design, communications systems, and ISO-NE procedures helped to avoid further problems. Actions taken nationally in response to the blackout include:

  - NERC accelerated adoption of a comprehensive set of measurable reliability standards. However, the standards remain voluntary and federal legislation is needed to make compliance mandatory.

  - NERC's readiness audit team examined whether each control area has adequate reliability features. It determined that ISO-NE is adequate overall and emphasizes reliability as a high priority.

- **New England cold snap of January 2004.** A unique set of circumstances during a cold snap in January, including curtailed generation imports, a shortage of natural gas for in-state generating facilities, and the decision of some generating facilities to resell their gas supply into the high-price market rather than use it to generate electricity, placed Maine at an unusually high risk of electricity supply shortage. Government and emergency agencies communicated throughout this period. The cold snap highlighted New England's vulnerability caused by its dependence on natural gas. Relevant companies and agencies subsequently developed near-term responses to this situation, including a new ISO-NE coordinating procedure, ISO/gas industry operating committees to address electricity-natural gas issues, and further ongoing studies of the interplay between gas and electricity generation.

Because of electric restructuring, the region now depends on market forces to assure that sufficient generating facilities are constructed to meet future regional electricity requirements. Recently, new gas-fired generation has provided excess capacity in most areas of New England. To provide for the future, FERC is conducting a long, complex proceeding to determine whether and how a Locational Installed Capacity Market (LICAP) should be implemented. The Maine PUC has been active in the proceeding, and is concerned that the ISO-NE proposal will be expensive and ineffectual.

The Physical and Cyber Security of Critical Grid Infrastructure

The utility industry, through various industry organizations, has identified best practices for the security and protection of critical grid infrastructure. Compliance is voluntary. However, in recent years, the industry has strengthened the guidelines and reporting to federal agencies and state regulators when repeated violations occur.

Increasing reliance on computer-based control systems has produced challenges associated with cyber security. NERC has issued a high-priority security standard that ISO-NE and Maine T&D utilities are working to implement.

As part of the State's homeland security planning efforts, state emergency organizations and the PUC are conducting a review of utility security improvements implemented since September 2001. All participants discuss and resolve potential issues. Both security and communication related to security are improving as a result.

Ongoing challenges include the high visibility of utility infrastructure, increased use of electronic control technologies, the interdependence among utility services, and the need to minimize the release of sensitive information. Overall, Maine's T&D utilities have improved their security measures, and utilities and state emergency agencies are continuing to evaluate security needs as they evolve.

II. INTRODUCTION

A. Legislative Background

During its 2003 session, the Legislature passed an Act to Encourage Energy Efficiency and Security.[3] The Act directed the Public Utilities Commission (Commission) to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution (T&D) utilities to promote energy efficiency and the security and robustness of the electric grid.[4] As required by the Act, the Commission submitted a report to the Joint Standing Committee on Utilities and Energy (the U&E Committee) on February 1, 2004. In its Report to the U&E Committee, the Commission stated that it believed that ensuring adequate service reliability through objective service quality metrics backed by meaningful penalties, incorporated as part of a utility's alternative rate plan (ARP), along with the Commission's ability to use its traditional tools to ensure adequate service, was working well. Accordingly, the Commission recommended that no legislative changes be made in this area at such time. The Commission stated that it would continue to monitor Maine's T&D utilities' service quality performance and refine the standards and penalty mechanisms in ways that improve their operation.

During the presentation of the Commission's Report, the U&E Committee indicated that it was interested in the continued examination of certain issues associated with grid reliability and security. In a letter to the Commission

[3]P.L. 2003, ch. 219.

[4]For purposes of this investigation, the Commission interpreted the term "security and robustness" to mean reliability of the system rather than protection against terrorist attacks.

dated February 23, 2004, the U&E Committee requested that as part of this follow-up examination, the Commission specifically:

1. quantify the safety margin of the grid system, including such indicators as maintenance activity, and to analyze how the margin may have changed over time, particularly as the result of alternative rate plans and restructuring;

2. assess the adequacy of grid security in light of the events of 9/11 and the blackout of 2003;

3. examine issues of grid adequacy in remote areas, e.g., Washington County, including looping issues; and

4. review relevant information including information from transmission and distribution utilities and reports on the blackout of 2003.

The U&E Committee requested that the Commission submit a report with its findings and recommendations during the next legislative session.

B. Description of the Commission's Investigation

On April 29, 2004, the Commission initiated an inquiry for the purpose of conducting the study requested by the Commitee.[5] Because the Commission anticipated that it would need to request information from the state's three investor-owned utilities (IOUs), Central Maine Power Company (CMP), Bangor Hydro-Electric Company (BHE) and Maine Public Service Company (MPS), they were considered to be parties to the process from the outset. In addition, the Commission included Eastern Maine Electric Cooperative (EMEC), a consumer-owned utility (COU), as a participant because EMEC owns and operates facilities that provide service to a significant portion of Washington County, an area of the state which the Committee specifically requested the Commission examine.[6] The Commission also invited the New England Independent System Operator (ISO-NE) to participate in the study process and noted that it was likely that the Commission would be seeking input and information from the ISO-NE during the course of the study. To assist our staff in conducting the study, the Commission retained the services of Liberty Consulting Group (Liberty), which has extensive experience in reviewing and auditing the reliability of electric T&D services.

[5]The Commission inquiry was docketed as *Maine Public Utilities Commission, Inquiry into the Adequacy of the Electric Grid in Maine,* Docket No. 2004-248.

[6]Given the issues requested to be investigated, and the time period allotted for the investigation, the Commission did not investigate the reliability of service of the state's seven other COUs as part of this investigation.

Following the initiation of the docket, the Commission's staff and consultants issued written data requests to CMP, BHE, MPS and EMEC seeking information from each of the utilities concerning the utilities' processes, planning, performance data, maintenance activities and investments, as they related to the areas of investigation. Following receipt of the utilities' responses, the staff and consultants conducted interviews with utility personnel. To the extent that utility personnel were unable to provide responses to questions during the interviews, the staff requested that the utility provide the information in writing. In addition to collecting information from the subject utilities, the staff also interviewed ISO-NE personnel and collected written information from ISO-NE as well as from the FERC and the North American Reliability Council (NERC). The staff has also, independent of this investigation, met on a regular basis with utility and law enforcement personnel in the state concerning utilities' preparedness against possible terrorist attacks.

A draft of the Commission's report was issued on March 28, 2005. Stakeholders were provided with an opportunity to comment on the draft. BHE, MPS, CMP, ISO-NE and Art Ray a former CMP employee, filed comments on the draft report. The comments are attached as Appendix A. Based on the information collected during the investigation, the advice and input of our consultants, and the comments received, the Commission submits the following Report.

C. Scope of the Report

In analyzing the areas requested to be investigated by the Committee, the Commission has divided the request into three separate and fairly distinct subjects:

1. the reliability of the distribution and local transmission system;

2. the reliability of the bulk-power transmission grid administered by ISO-NE; and

3. the security of critical grid infrastructure.

Even with the help of Liberty Consulting and the commitment of significant staff resources, given the extremely broad scope of the project, the Commission necessarily views the examination conducted here as a general review, somewhat akin to a general physical examination by a treating physician. This general examination would then allow the Commission to determine whether the grid is in basic good health; whether there are certain signs or symptoms which warrant further investigation or examination; and finally, whether certain conditions which were discovered during the general examination, warranted immediate attention or correction. We believe that this Report makes those determinations.

For the most part, the T&D utilities in the state are reasonably maintaining the grid and there is a sufficient "safety margin" going forward. In certain instances, however, further examination is warranted. The Commission intends to initiate proceedings in the coming year to conduct these follow-up examinations. In other instances, we believe that certain conduct requires immediate attention and correction and we will be taking the necessary steps in the coming months to ensure that such deficiencies are corrected. The Commission does not believe, however, that any legislative action is required at this time.

The report of the Commission's consultants is attached as Appendix B to this report. The Commission has reviewed the Liberty Report and supports the conclusions and recommendations contained therein. This Report, provides the Commission's conclusions, together with the Commission's findings and analysis which are in addition to those contained in the Liberty Report. We have, to the greatest extent possible, tried to avoid repeating the content of the Liberty Report. Therefore, we recommend that the reader initially review the Liberty Report before reading the Commission's findings.

Prior to providing the Commission's findings and recommendations, this Report provides a brief background on the regulatory paradigm in Maine as it affects the subject areas of the study.

III. REGULATORY PARADIGMS

A. Bulk Power System

The bulk electric power system that serves most of North America consists of three grid networks – an interconnected network roughly west of the Rockies, a second network serving most of Texas, and a third very large network serving the rest of the United States and eastern Canada – with limited ties between those networks. Because the nation's power grid is largely an interstate (and international) system of interconnected networks, its oversight falls to the federal government and the industry participants that own and operate the largely privately-owned and operated system.

In addition, regional industry councils set criteria and standards and have an oversight role in ensuring the reliability of the grid. Adherence to the rules and standards of these councils has historically been voluntary, an issue of continuing concern. This section of the Report describes the various oversight entities that most directly affect Maine.

1. FERC

The Federal Energy Regulatory Commission (FERC) is a federal agency that regulates the interstate transmission of electricity, natural gas, and oil.[7] FERC also regulates natural gas and hydropower projects. As part of those responsibilities, FERC:

- regulates the transmission and wholesale sale of electricity in interstate commerce;
- licenses and inspects private, municipal, and state hydroelectric projects;
- oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives;
- regulates the transmission and sale of natural gas for resale in interstate commerce;
- approves the siting and abandonment of interstate natural gas facilities, including pipelines, storage and liquefied natural gas;
- regulates the transmission of oil by pipeline in interstate commerce; and
- administers accounting and financial reporting regulations and conduct of regulated companies.

2. NERC

In carrying out its responsibilities in the electric sector, FERC works closely with the North American Electric Reliability Council (NERC). NERC is a not-for-profit corporation whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Formed in 1968 as a response to the 1965 northeast blackout, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure, and the mutual self-interest of all participants.[8]

In addition, NERC is involved in bulk power system security. The U.S. Department of Energy has designated NERC as the electricity sector's information sharing and analysis center (ISAC) coordinator for critical infrastructure protection. NERC receives security data from electricity sector entities; analyzes the data with input from the Department of Homeland Security

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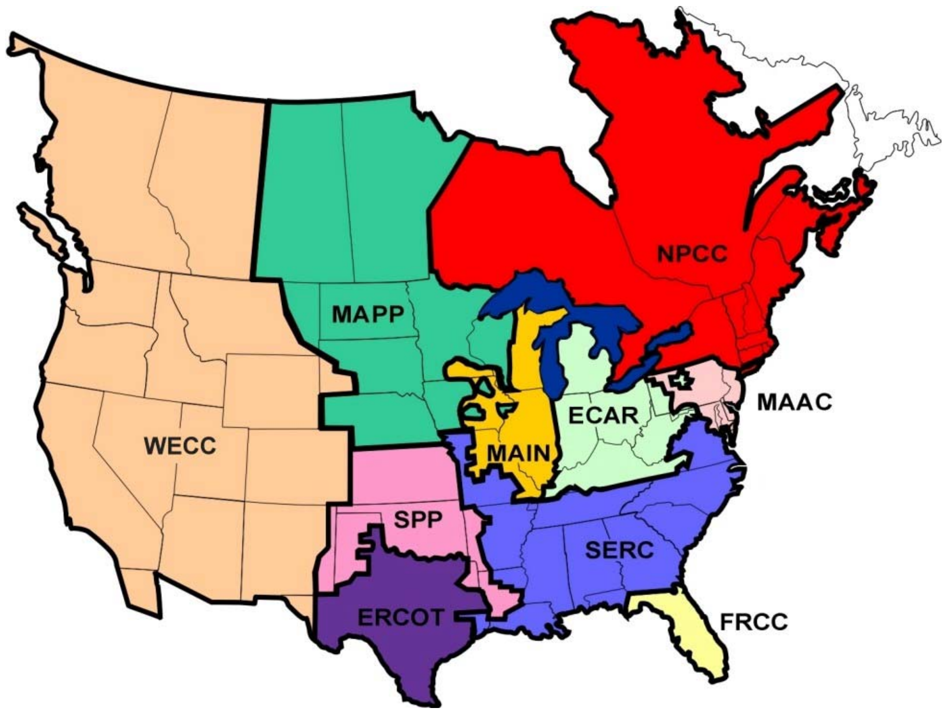
[7] http://www.ferc.gov/about/ferc-does.asp .

[8] http://www.nerc.com .

(DHS), other federal agencies, and other critical infrastructure sector ISACs; and disseminates threat indications, analyses, and warnings to sector entities.

NERC is composed of ten Regional Reliability Councils. The members of these councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.

The areas of responsibility of the ten Regional Reliability Councils are shown on the following map.



3. NPCC

The Northeast Power Coordinating Council (NPCC) is the Regional Reliability Council for the northeastern United States and most of eastern Canada. NPCC sets reliability standards for the region and coordinates the design and operation of the bulk power supply system in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, the Canadian Maritime Provinces, Québec, and Ontario.[9] NPCC reviews all bulk

[9] http://www.npcc.org .

power system modifications proposed by regional entities to ensure that the integrity of the regional system is maintained.

4. ISO-NE and Maritimes

Within NPCC, five sub-regional control centers are responsible for the day-to-day operation and control of bulk power generation and transmission facilities in their areas, and related administration of the power markets in those areas. Most Maine consumers (i.e., those served by CMP and BHE) are interconnected with the New England bulk power system operated by ISO New England, Inc. (ISO-NE)[10], a not-for-profit corporation created in 1997. ISO-NE also oversees and administers the New England wholesale market and, in addition, acts as the regional reliability coordinator for the New England states and the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island.

Northeastern Maine (i.e., the area served by MPS and EMEC) is interconnected with the Canadian Maritimes system and is connected to the rest of Maine and New England only by transmission through New Brunswick. The Northern Maine ISA, Inc. (NMISA), headquartered in Bangor, administers the market system that serves these consumers.

Regional control area operators and administrators, including ISO-NE and the Northern Maine ISA, are regulated by FERC. The Maine PUC participates on ISO-NE committees, monitors ISO-NE developments both directly and through the New England Conference of Public Utilities Commissioners (NECPUC), and often files comments before FERC on ISO-NE proposals and other filings related to the New England wholesale electric markets.

Within ISO-NE, there are currently four satellite local control centers (LCC's) that monitor and perform hands-on transmission line switching functions for their portion of the system: 1) the Connecticut Valley exchange (CONVEX); 2) Rhode Island, eastern Massachusetts, and Vermont (REMVEC); 3) New Hampshire; and 4) Maine.[11] CMP operates the Maine satellite control center for ISO-NE. ISO-NE requires its system operators to maintain professional certification to meet NERC standards. NERC certification is not mandatory, however, for operators at the satellites.

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[10] http://www.iso-ne.com/ .

[11] The ISO-NE satellite structure may change over time, based on circumstances that affect NEPOOL participants and wholesale market issues. For example, VELCO will begin operation as an LCC in July, and additional satellite centers may be established within the New England region as markets evolve.

ISO-NE also oversees bulk system maintenance activities to ensure that adequate levels of supply and transmission will be available. Regional transmission operators are required to notify ISO-NE in advance of any maintenance that may affect transmission facilities. If work is to be performed at a critical transmission facility, the schedule is subject to approval by ISO-NE.

On February 1, 2005, ISO-NE began operating as a Regional Transmission Organization (RTO) under the jurisdiction of the FERC. As an RTO, ISO-NE assumes complete responsibility for the day-to-day operations of the New England transmission grids and has authority to direct the construction of new transmission plant as needed. The transmission owners, such as CMP and BHE, will continue to own, physically operate, and maintain the transmission facilities, and be paid for the transmission services they provide.

ISO-NE is also responsible for regional system planning and develops a comprehensive needs assessment of the New England bulk power system. The 2004 regional system plan (RSP) discusses the needs of the entire six-state region, including Maine. The RSP provides signals for market solutions (e.g. generation, conservation, merchant transmission) to address reliability concerns and identifies transmission projects as a backstop for reliability in the event that market responses are not adequate. The RSP is reviewed annually through an open and ongoing stakeholder process that includes participation from transmission companies, state government representatives and other interested parties through the Planning Advisory Committee (PAC).[12]

B. Restructuring in Maine

For the entire twentieth century, Maine's utilities were vertically integrated monopolies with respect to all aspects of providing and delivering the electricity "product." Because of their monopoly status, the Maine Commission regulated all aspects of the retail transactions between Maine utilities and their ratepayers.

On March 1, 2000, Maine's electric industry was restructured to provide Maine consumers with the opportunity to purchase generation services from a competitive market (retail access). As of that date, the generation portion of electricity service was no longer subject to rate regulation in Maine and, perhaps more noteworthy from a reliability perspective, was no longer the

[12] For a full discussion of the reliability of the New England power system, including Maine, please refer to the full RSP report. A summary of the 2004 plan (RTEP04) and the PAC stakeholder meeting materials related to the development of the 2005 plan are available online at : http://wwwiso-ne.com/committees/planning_advisory_committee/. For access to the full RTEP04 report, contact ISO-NE Customer Service at (413) 540-4220.

responsibility of the regulated public utility. Instead, decisions regarding the construction of and prices charged for generation, now occur within a competitive market.

As a result of restructuring, the bundled electricity "product" has been separated into four parts: (1) the generation component; (2) the transmission component; (3) the distribution delivery component; and (4) the stranded cost component. The unbundling of generation costs from utility rates has resulted in FERC asserting jurisdiction over retail transmission rates. Currently, CMP, BHE and MPS's transmission rates are reset annually by FERC based on the prior year's transmission sales and transmission related costs. While FERC clearly has asserted jurisdiction over retail transmission rates, and previously had jurisdiction over the bulk power transmission system, FERC has not, as of this date, clearly asserted jurisdiction over local transmission systems and the jurisdiction over reliability matters for this portion of the grid remains somewhat unclear.

C. Alternative Regulation in Maine

In late 1993, following a series of rate increases resulting from a number of causes, including declining sales brought on by a downturn in the economy, introduction of a new rate design, and increases in utility costs above the rate of inflation, the Commission concluded that it should consider setting CMP's rates through a rate cap approach.[13] Under the rate cap approach, a utility's rates are reset based on an external index over a multi-year period, rather than the "cost-plus" methodology used under traditional rate of return regulation. The Commission ultimately approved an alternative rate plan for CMP in 1995.[14]

CMP's first five-year price-cap plan (ARP I) reset CMP's rates annually based on an external index calculated by inflation minus a productivity offset, plus or minus earnings outside a deadband and/or certain costs which qualified as mandated costs. Because cost reductions in excess of the indexed rate change would flow directly to the utility's bottom line under an ARP, the Commission recognized that there was an enhanced incentive, relative to traditional regulation, for a utility to cut costs, including ways that could damage system reliability. To address this issue, ARP I included penalties of up to $3 million if CMP failed in any year to meet the standards set forth in the ARP's Service Quality Index (SQI).

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[13] *Central Maine Power, Proposed Increase in Rates,* Docket No. 92-345, (Dec. 14 1993).

[14] *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345(II) (Jan. 10, 1995).

ARP I's SQI measured CMP's performance in five areas, of which two addressed reliability and three concerned customer service. The reliability indices included were the System Average Interruption Frequency Index (SAIFI), which measures the average frequency of sustained interruptions per customer over the year[15], and the Customer Average Interruption Duration Index (CAIDI), which is the average time required to restore service to the average customer per sustained interruption.[16]

In approving ARP I, the Commission concluded that the specific service quality standards of the SQI, with automatic penalties assessed if service deteriorated beyond baseline levels, were superior to the traditional tools of penalizing the Company for poor service through litigated proceedings. In the Order approving CMP's ARP I, however, the Commission clearly and emphatically stated that the Commission's approval of an ARP did not place the utility on "auto-pilot" and was not tantamount to deregulation:

> No one should interpret our adoption of the Stipulation as a willingness to abandon our central regulatory task of ensuring that CMP's customers receive adequate service at just and reasonable rates. Indeed, the Stipulation explicitly preserves the full panoply of traditional regulatory tools that would permit our intervention if it appears that the new form of regulation is operating against this central objective, and in fact creates new tools to help ensure that service quality and demand-side management objectives are met.[17]

In 2000, the Commission approved a second alternative rate plan for CMP (referred to as ARP 2000) applicable in the newly restructured environment.[18] Because generation service was now subject to market competition, and because FERC had asserted jurisdiction over transmission rates following a state's unbundling of generation from delivery service, ARP 2000 only applies to distribution delivery rates and service. Similar to ARP I, ARP 2000 adjusts rates annually by a formula of inflation minus a productivity offset adjusted for mandated costs, earnings sharing, and service quality penalties. ARP 2000's SQI mechanism contains the same two indices, CAIDI

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[15] The SAIFI formula is:

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

[16] The CAIDI formula is:

$$\text{CAIDI} = \frac{\sum \text{customer durations}}{\text{Total number of customer interruptions}}$$

[17] *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345 (II) Detailed Opinion and Subsidiary Findings at 2 (Jan. 10, 1995)

[18] *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger), "ARP 2000,"* Docket No. 99-666 (Nov. 16, 2000).

and SAIFI, to measure reliability. Although CMP's distribution revenues going into ARP 2000 were only one-third of its revenues under ARP I, the ARP 2000 plan increased the maximum penalty level for failing to meet the SQI standards from $3.0 million to $3.6 million. In addition to the SQI performance metrics, under the terms of ARP 2000, CMP is required to file an Annual Reliability Improvement Report which, among other things, contains a service area specific analysis of reliability and which identifies CMP's worst performing circuits and sets forth both the planned and undertaken improvements to address such circuits.

During 2002, the Commission approved an ARP for BHE.[19] Similar to CMP's ARP 2000, the BHE ARP applies only to distribution rates, which are subject to change annually based on an external index formula. The BHE ARP also contains an SQI mechanism which includes CAIDI and SAIFI performance metrics. Under the BHE ARP's SQI mechanism, BHE faces penalties up to $840,000 should its service not meet the established standards.[20] Similar to CMP's ARP 2000, the BHE ARP requires BHE to file an Annual Reliability Improvement Report with the Commission at the time it submits its annual price change information.

During 2003, MPS submitted a proposal to the Commission requesting a $1.267 million increase in distribution revenues as a "starting point" adjustment for its proposed seven-year ARP. The Commission approved a stipulation which resolved the Company's "starting point" revenue requirement request but did not address MPS's proposed ARP.[21] Under the terms of the stipulation, MPS was given until the end of 2003 to determine whether it wanted to pursue its ARP proposal. MPS informed the Commission that it did not wish to pursue its ARP proposal at such time. MPS is therefore, the only investor-owned utility whose distribution rates remain subject to traditional regulation.

D. Corporate Reorganizations

Consistent with trends in the electric utility industry, both CMP and BHE have been the subject of merger acquisitions during the past five years. On January 4, 2000, the Commission approved the merger of CMP and Energy East, Inc. under which CMP became a wholly owned subsidiary of Energy East,

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[19] *Bangor Hydro-Electric Company, Request for Approval of Alternative Rate Plan,* Docket No. 2001-410 (June 11, 2002).

[20] BHE's penalty level of $840,000 represents approximately 1.5% of BHE's distribution delivery revenue requirement and is, thus, comparable in scale to CMP's ARP maximum penalty level.

[21] *Maine Public Service Company, Request for Approval of Alternative Rate Plan,* Docket No. 2003-085 (Sept. 3, 2003).

and on January 5, 2001, the Commission approved the merger of BHE and Emera, Inc. under which BHE became a wholly owned subsidiary of Emera, Inc.[22]

In approving the CMP merger, the Commission recognized that service quality could deteriorate when a Maine utility becomes part of a larger multi-state firm. The Commission concluded that such a decline would be unacceptable and put CMP on notice that it intended to closely examine service quality during CMP's then upcoming ARP 2000 proceeding. In the orders approving the CMP/Energy East merger and the BHE/Emera merger, the Commission required the utilities to file annual capital and O&M budget information with the Commission so that it could monitor investment activity by the utility post-merger.

IV. RELIABILITY OF THE DISTRIBUTION AND TRANSMISSION SYSTEM

A. Assessment Criteria

In measuring the reliability of the distribution and local transmission system we first assess each utility's performance in terms of the ARP service reliability criteria, SAIFI and CAIDI.[23] As discussed previously, SAIFI is designed to provide information regarding the average frequency of sustained interruptions[24] per customer over a predefined area and period of time and is considered to be a good indicator of the condition of a utility's plant, as well as the quality of the utility's maintenance and tree trimming activities. CAIDI represents the average time required to restore service to the average customer per sustained interruption and is considered to be a good indicator of the quality of a utility's response to outages.

Both CMP and BHE are allowed, under their respective ARPs, to exclude SAIFI and CAIDI results on days when a significant portion of the customer base suffers an outage. This allows the removal of data incurred

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[22] *CMP Group, Inc., et. al., Request for Approval of Reorganization and of Affiliated Interest Transactions,* Docket No. 99-411, Order (Jan. 4, 2000); and *Bangor Hydro Electric Company, et. al., Request for Approval of Reorganization (Joint Petition),* Docket No. 2000-663, Order Rejecting Revised Stipulation and Approving Original Stipulation (Jan. 5, 2001).

[23] Although MPS and EMEC are not operating under alternative rate plans, both calculate SAIFI and CAIDI performance.

[24] Pursuant to the Institute of Electrical and Electronics Engineers, Inc. Standards Board (IEEE) standard 1366, a "sustained interruption" is "any interruption not classified as a momentary event. Any interruption longer than 5 minutes."

during “extraordinary events” in which the utility cannot reasonably be expected to meet its performance benchmarks. This prevents the utility from being penalized for extraordinary events, such as hurricanes or major ice storms, that are outside its control and outside the norm for outages.

Because the ARP's CAIDI and SAIFI criteria are calculated on a company-wide basis, it might be possible to achieve reasonably good average numbers (and thus avoid incurring any penalties), by providing good service in densely populated areas while performing poorly in more rural areas. Therefore, in addition to reviewing overall SAIFI and CAIDI performance, we have looked at SAIFI and CAIDI performance by circuit and compared such performance with the worst performing circuits identified by CMP and BHE in their ARP Annual Reliability Improvement Reports.

We also recognize that SAIFI and CAIDI statistics provide only a snapshot of current utility performance. Because failure to make necessary investments in the grid or to follow reasonable maintenance practices may not result in a deterioration of service for a number of years, it is possible to maintain reasonable SAIFI and CAIDI numbers while sacrificing reliability in the future, for cost savings and profits today. As a means of addressing this issue, we also examined the utilities' maintenance and inspection programs, capital and maintenance spending, vegetation management programs and spending, and the utilities' planning criteria and procedures for system improvements. Because the utilities' transmission and distribution systems are distinct, both in terms of operation and function, the commission separately evaluated the transmission and distribution operations of each utility. The Commission's findings by utility are presented below.

B. <u>CMP</u>

1. <u>Transmission</u>

a. <u>Overview</u>

Based on the information provided during the study process, CMP’s planning, design and operation of its transmission plant (both bulk power and local transmission) appear to be consistent with industry standards and good utility practices. CMP uses five specific reliability indicators: event frequency; event duration; loss of load; expected unserved energy; and number of customers affected, to identify and prioritize system problems. The use of these indicators, along with CMP's transmission inspection programs, discussed in section IV(B)(1)(d), *infra*., make it likely that CMP will detect problems on the transmission system which could degrade reliability.

CMP’s transmission and substation system is designed to ensure that conductors, equipment and transformers do not exceed assigned normal and emergency ratings and appears to be fully compliant with ISO-NE and NPCC requirements for operation of the bulk transmission system.

b. Capital and O&M Spending

CMP's transmission spending since 1994 appears to be relatively consistent and thus, does not by itself, raise concern. CMP's capital, operations, and maintenance spending on its transmission system during the 1994-2003 time period are presented in Table I below. As noted from the information contained in the table, CMP's capital spending increased immediately following restructuring. CMP has explained this increase as being related to capital projects which were planned for future years but were accelerated to accommodate new merchant generators which came onto CMP's system after restructuring or which were related to capital needs discovered during the interconnection of these new generators.

Table I
CMP Transmission Spending

Year	Plant Additions $	Operations Expenses $	Maintenance Expenses $
1994	4,337,000	9,569,000	4,440,000
1995	4,668,000	9,705,000	4,677,000
1996	2,495,000	11,520,000	3,828,000
1997	2,707,000	13,367,000	3,392,000
1998	1,433,000	17,743,000	3,383,000
1999[25]	1,217,000	9,954,000	4,030,000
2000[26]	9,340,000	15,338,000	5,037,000
2001	5,559,000	11,508,000	3,997,000
2002	9,066,900	11,702,000	4,419,000
2003	2,454,000	13,486,000	4,137,000

c. Vegetation Management

[25] Operations Expenses after 1999 do not include congestion expenses and costs assessed for regional services by ISO-NE. Congestion expenses refer to increased generation costs caused by congested transmission points (e.g. Boston, Southwest Connecticut) and until March 2003 were spread over all transmission owners in the region based on the utilities' load share.

[26] Plant additions for 2000, 2001 and 2002 are less amounts for capital projects to interconnect new merchant generators.

CMP's transmission vegetation management plan calls for four-year cycle aerial, ground and side manual trimming.[27] This four-year cycle and plan is consistent with recommendations contained in the August 2003 Blackout Report by FERC, which noted that five-year cycles should be shortened.[28] CMP's right-of-way management practices for corridor widths, wire and border zone clearances on its transmission system are reasonable, consistent with good utility standards, and well within NPCC and FERC recommendations.

CMP's transmission vegetation management spending and performance (measured in terms of brush acres) are set forth in the Table II below.

Table II
CMP Transmission Vegetation Management Activity

Year	Dollars Spent	Brush Acres
1994	$1,477,210	9304
1995	$1,513,033	7264
1996	$1,710,707	8919
1997	$1,449,101	6728
1998	$1,391,832	9304
1999	$1,450,759	7264
2000	$1,714,984	8919
2001	$1,689,768	6728
2002	$1,708,522	9304
2003	$1,854,881	7264

The spending levels have increased with inflation, and, as reflected in the table, have been adequate to maintain a consistent level of brush acres trimmed per year.

d. Inspection Programs

CMP performs helicopter patrol of all of its transmission sections and lines each spring or anytime that conditions may warrant. CMP has a 10-year cycle for transmission line foot patrol inspections with the exception of its 345 kV lines, which are done annually. The ten-year foot

[27] Cycle trimming refers to the practice of trimming particular areas of the system at designated intervals so that the entire system would have been completely trimmed at the end of the predetermined period or cycle.

[28] Vegetation Management and Bulk Electric Reliability Report From the Federal Energy Regulatory Commission (FERC) December 7, 2004.

patrol inspection consists of a combination of pole and line inspections that include ground line inspections and sounding of poles to identify any poles that may have deteriorated and are of insufficient strength. Poles identified as showing deterioration are then evaluated to determine if they should be scheduled for repairs, should be changed out based on their condition, or if a treatment program could extend their life. CMP visits and inspects its substations on a monthly or semi-monthly basis depending on the type, size and voltage of the substation. During the substation inspection, the company examines specified equipment and apparatus.

CMP maintains a checklist that tracks all repairs and defects found on the transmission and substation systems. Any known problems are documented and then prioritized for repair. Emergency repairs are made immediately. CMP also infrared inspects its transmission and substations once a year.[29]

CMP's stated goal is to complete 100% of its scheduled maintenance work every year. At times, a schedule may not be completed and, if so, the remaining schedule is moved into the next year with a goal to not only complete the original schedule but anything carried over as well. CMP reported a 100% completion rate for 2003, which appears to be generally consistent with past practice.

We find CMP's transmission inspection program to be well-designed and implemented and consistent with sound utility practice. The transmission inspection program appears to meet all requirements of the NESC, NPCC and FERC.

2. Distribution

a. ARP Performance

Under its first ARP, CMP was subject to a penalty if average service interruptions per customer during the year (SAIFI), after exclusions, exceeded 2.0 and also if its customers experienced an average greater than 3.0 hours of annual service interruption per customer (CAIDI) during the year, after exclusions.[30] Under the Company's ARP I SQI mechanism, the service reliability outage exclusion provision exempted all days in which

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[29] Infra-red inspections refer to the process of using thermovision equipment to thermally scan the system to locate hot spots on conductors and equipment caused by loose connections or hardware and other defects.

[30] *See Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345(II), Order Approving Stipulation (Dec. 30, 1994), *and* Detailed Opinion and Subsidiary Findings (Jan. 10, 1995).

customer outage hours exceeded 0.8 times the number of CMP customer accounts in that month.[31] This threshold was applied on a company-wide basis.

Under ARP 2000 as initially approved, CMP was to be penalized if its customers experienced an average SAIFI greater than 1.80 and also if its customers experienced an average CAIDI greater than 2.58 hours.[32] Under the Stipulation approved by the Commission for ARP 2000, when more than 10% of the customers in one of the company's eleven service areas were affected by outages, all outages occurring in that service area associated with that event were excluded for the duration of that outage from the CAIDI and SAIFI calculations.

Because some of CMP's service areas are small, e.g. 18,000 customers, outages affecting as few as 1,800 customers were automatically being excluded from the CAIDI and SAIFI calculations. On December 12, 2003, as part of CMP's SQI mid-period review, the Commission issued an Order Approving Stipulation that modified the outage exclusion criterion to 10% of CMP's customers on a company-wide basis. At the same time, the SAIFI benchmark was changed from 1.80 interruptions per year to 2.10 interruptions per year and the CAIDI benchmark was decreased from 2.58 hours of interruptions per year to 2.32 hours of interruptions per year.[33] These changes in the benchmarks were intended to reflect both the change to the exclusion criterion and improved outage reporting by the company.[34]

During both ARP I and ARP 2000, CMP has consistently met its company-wide annual SAIFI and CAIDI performance targets.

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[31] See *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345, (Jan. 10, 1995) Order Approving Stipulation, Appendix Attachment G at 2. For example, for a hypothetical base of 500,000 customer accounts, any day with over 400,000 customer-hours of outage would be excluded from the SQI calculation under this mechanism.

[32] *See* Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post Merger) “ARP 2000,” Order Approving Stipulation, Docket No. 99-666, (Nov. 16, 2000).

[33] *See Maine Public Utilities Commission Investigation, Mid Period Review of CMP's ARP 2000 Service Quality Indices,* Docket No. 2002-445, Order Approving Stipulation (Dec. 12, 2003).

[34] According to CMP, the company automated its outage reporting process in 2002. This has resulted in more small scale outages being reported which results in higher SAIFI numbers but due to the small scale nature of the outages actually tends to decrease the time per outage or CAIDI calculation.

CMP's company-wide SAIFI and CAIDI performance, with exclusions then in effect, are presented in Table III below.

Table III
CMP Company-Wide ARP Performance - With Exclusions

Year	SAIFI Performance	SAIFI Target	CAIDI Performance	CAIDI Target
1995	1.41	2.00	2.63	3.00
1996	1.30	2.00	2.38	3.00
1997	1.29	2.00	2.01	3.00
1998	1.88	2.00	2.05	3.00
1999	1.47	2.00	1.80	3.00
2000[35]	1.75	2.00	2.40	3.00
2001	1.45	1.80	2.01	2.58
2002	1.72	1.80	1.97	2.58
2003	1.72	1.80	1.82	2.58

Because CMP's exclusion criterion has changed several times during the course of its two ARPs, to gauge CMP's performance over time, it is useful to review CMP's performance on a pre-exclusion basis. Looking at the data on a pre-exclusion basis also enables one to see how the utility is reacting to all types of events, including storms which might be considered severe or extraordinary. Table IV shows CMP's annual SAIFI and CAIDI performance since 1996 without extraordinary event exclusions.

Table IV
CMP company-wide ARP Performance Without Exclusions

YEAR	SAIFI	CAIDI
1996	2.27	3.57
1997	1.61	2.21
1998	4.73*	15.22*
1999	1.89	2.27
2000	1.98	2.77
2001	1.90	3.08
2002	2.53	3.56
2003	2.33	3.55

*Reflects outage data from 1998 Ice storm.

[35] CMP's ARP I expired at the end of 1999 and no ARP metrics were in effect for 2000. However, by way of our order approving the CMP/Energy East merger, we extended the ARP I SQI standards until CMP's next ARP was put in place.

As seen from the Table, over the 1996 through 2003 time period, both CMP's SAIFI and CAIDI performance seemed to improve initially and then deteriorate somewhat over the later years to a point at which performance in the final year (2003) essentially equaled performance in the initial year (1996). Improved reporting by CMP in the later years, may in part explain the higher SAIFI numbers, and thus CMP's 2003 performance may actually be better relative to 1996 than is reflected in the numbers.

b. Reliability Criteria By Circuit

CMP's distribution system consists of 420 circuits, with customer density per circuit ranging from 5,806 customers to 30 customers.[36] Because the SAIFI and CAIDI targets in CMP's ARP are based on total customer interruptions and total customer hours of interruption, an outage in a more densely populated circuit will have a much greater impact on the company-wide SAIFI and CAIDI calculations than will an outage in a less densely populated circuit. The overall company calculations then, do not identify poor performance in particular areas of CMP's territory. Therefore, the Commission also examined CMP's (and BHE's) circuit by circuit performance and worst performing circuit performance, in terms of CAIDI and SAIFI, as part of this investigation.

The examination of CMP's "worst performing circuits", as identified using actual circuit SAIFI and CAIDI performance (without exclusions), shows a great disparity between the company-wide average and the actual per circuit performance for the worst performing circuits. CMP's worst performing circuits in terms of SAIFI and CAIDI are provided in Appendix C and Appendix D. Table V, below, compares the company's worst SAIFI performing circuit, the average of the ten worst SAIFI performing circuits, and the company-wide average SAIFI, along with the average number of customers on the ten worst SAIFI circuits, for the last three years.

Table V
CMP Worst Circuit Analysis - SAIFI (without exclusions)

Year	Worst Circuit Performance	Avg. SAIFI 10 Worst Circuits	Company-Wide SAIFI Performance	Avg. # Customers Per Circuit 10 Worst Circuits
2001	55.97	31.21	1.90	455
2002	70.60	23.13	2.53	861
2003	39.18	20.36	2.33	713

[36] CMP does have one circuit with only one customer on it. For our purposes here, we have assumed that this circuit to be a dedicated private line type circuit.

As set forth above, the average number of customers on the 10 worst SAIFI performing circuits was 455 in 2001, 861 in 2002 and 713 in 2003. In 2003, the average number of customers per circuit for CMP was 1,547. The disparity between CMP's worst SAIFI performing circuits and its company-wide SAIFI performance, and the fact that these worst performing circuits are almost entirely within CMP's less densely populated areas is of concern to the Commission.

CMP's reaction to these poorly performing circuits also raises concerns. As part of its annual ARP 2000 filing, CMP is required to submit a list of its worst circuits and the action taken, or planned to be taken, to improve performance on such circuits. As noted in Appendix C, in 2001 and 2003 only one of the worst performing SAIFI circuits was identified by CMP as a "worst performing circuit" in its Annual Reliability Improvement Report while in 2002, none were listed.

During the interview process, CMP conceded that it concentrated its improvement actions on those circuits which would provide the greatest impact on overall company SAIFI performance since this is how the ARP penalty mechanism is calculated. Consistent with this approach, in 2003, CMP modified the method it used to calculate its worst-performing circuits from a SAIFI by circuit calculation which we have used here and which divides the number of customer interruptions on that circuit by the number of customers served on that circuit, to a contribution to overall SAIFI methodology, which divides the number of customer interruptions on the circuit by the total number of customers, company-wide. Because the denominator, the number of customers, remains fixed in CMP's company-wide methodology and because the number of customer interruptions on CMP's more densely populated circuits is likely to be greater in absolute terms than on CMP's more sparsely populated circuits, CMP's methodology tends to give much greater weight to its more densely populated circuits. In 2003, for example, the average number of customers per circuit on the circuits identified by CMP in its 2003 Annual Reliability Improvement Program as its "worst performing circuits" was 3,400, or slightly double the average number of customers per circuit for CMP.

In its response to the Commission's Draft Report, CMP states that it has, as part of its ARP 2000 annual filing, been identifying its ten worst circuitsand has identified and developed improvement plans for rural circuits. CMP also notes that the lack of complaints from customers is further evidence that CMP consistently delivers high quality service to its rural customers.

The Commission is concerned by the possibility, that while CMP, on an overall basis, is meeting the service quality standards of the ARP, its performance in its less densely populated areas in its service territory may have deteriorated, and in some service areas may no longer be adequate. In reaching this conclusion, we recognize that service quality in every area of a utility's service territory will not, and need not, be identical and that concentrating repairs or maintenance in areas which will provide the most in the way of improved quality of service for the most number of customers will often make sense from an economic or efficiency perspective. It is imperative, however, that service to all of the utility's customers, including those in less densely populated areas, does not fall below what would generally be considered minimum levels of adequate service.

c. Outage By Cause Code

Appendix E provides CMP outage data from 1996 through 2003. On an overall pre-exclusion basis, CMP outages have gone up by 36% during the period. Tables 1 through 5 of Appendix E break down the outage data by cause code. Of particular note, is the growth in the number of outages due to equipment failure and "unknowns." During the interview process, CMP indicated that outages classified as "tree contact", "weather" and "unknown" were essentially all tree-related. The outage data for these three categories combined, shows a general decline in number of outages through the year 2000, and then a steady increase through the year 2003. The fact that CMP has been able to meet its overall SAIFI and CAIDI targets despite the overall increase in outages suggests that more outages are occurring on CMP's less densely populated circuits, which would be consistent with the SAIFI by circuit data discussed above.

Table VI
CMP Tree Related Outages since 2000

Year	Tree/Weather Combined Outages
2000	2,800
2001	3,848
2002	4,594
2003	4,705

d. Capital and O&M Spending

While CMP's spending on distribution operations has grown significantly since 1994, CMP's spending on distribution capital plant and distribution maintenance has been essentially flat since 1998. Distribution spending levels since 1994 are presented in Table VII below.

Table VII
CMP Distribution Spending Levels

Year	Capital Additions $ in Thousands	Operations $ in Thousands	Maintenance $ in Thousands
1994	25,394	23,199	12,746
1995	31,382	21,318	14,166
1996	28,013	25,006	17,524
1997	26,383	27,543	15,110
1998	29,850	25,166	22,314
1999	29,925	29,176	18,602
2000[37]	32,633	33,867	20,103
2001[38]	40,768	32,652	20,954
2002	26,156	37,581	20,721
2003	29,485	39,688	21,581

These spending levels are fairly consistent, and taken by themselves, do not raise any significant concerns.

e. Vegetation Management

CMP's spending on its distribution vegetation management programs increased significantly during the period of 1994 to 1999 and has been fairly flat since that time.

Table VIII
CMP Distribution Vegetation Management Spending

Year	Maintenance	Hot Spot	Hazard Tree Program	Total
1994	$3,755,471	$1,962,522	N/A	$5,717,993
1995	$3,754,924	$1,882,956	N/A	$5,637,880
1996	$6,488,674	$2,338,406	N/A	$8,827,080
1997	$7,286,159	$1,518,157	N/A	$8,804,316
1998	$6,453,765	$1,385,477	N/A	$7,839,242
1999	$7,899,510	$1,193,222	N/A	$9,092,732
2000	$7,902,244	$1,150,025	N/A	$9,052,269
2001	$8,116,898	$ 819,725	$ 209,000	$9,145,623
2002	$6,647,058	$ 900,002	$ 329,211	$7,876,271
2003	$7,876,355	$ 596,770	$ 440,380	$8,913,505

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[37] Maintenance costs for 2000-2003 do not include the amortization of restoration costs incurred during the Ice Storm of 1998.

[38] 2001 plant additions include approximately $10-11 million related to the reversal of accounting entries for plant not actually retired.

CMP tracks the amount of vegetation management work performed on its distribution system by the number of spans worked on. The work activity tracks fairly closely with the expenditures and is presented in Table IX.

Table IX
CMP Distribution Vegetation Management Activity

Year	Total Maintenance Spans Worked	Hot Spot Spans Worked	Hazard Tree Spans Worked	Total Spans Worked
1994	28,632	14,402	-	43,034
1995	25,424	13,716	-	39,140
1996	56,850	20,781	-	77,631
1997	62,393	12,132	-	79,525
1998	42,118	10,716	-	52,834
1999	56,220	8,805	-	65,025
2000	50,205	7,449	-	57,654
2001	48,793	4,976	1,048	59,817
2002	39,365	4,988	1,294	45,647
2003	60,591	3,452	1,639	65,682

During the early 1990's to 1995, CMP's operating procedures called for five-year cycle trimming. According to CMP, this program was not consistently followed and the lack of resources prevented a completion of the cycle. In 1995, CMP migrated to what might be termed a "trouble-based" system of vegetation management. At the present time, CMP currently uses a variety of criteria to plan its distribution vegetation work. The primary parameter considered is the SAIFI for each circuit. The other major areas of consideration include the prior year's SAIFI, the number of tree-caused power outages, visual inspection of tree and brush conditions by a qualified CMP arborist, a review of power quality issues, distance of circuits from service center, and coordination with CMP betterments or MDOT projects. Based on the above criteria and resources allocated, CMP develops an annual work plan that targets particular segments or spans of a circuit. During the interview process, CMP representatives were asked if they could identify what particular spans were last worked on. CMP stated that the information was included in its GIS mapping system but could not be readily retrieved.

The Commission finds that CMP's shift from a cycle-based trimming program to a more targeted type program is not, in itself, unreasonable. Indeed, in looking at BHE's targeted program, see section IV(C)(2)(d), it appears that such a program can actually increase the program's productivity. The Commission is concerned, however, with the design of CMP's program, in that it appears to be primarily reactive, and targets areas only after a service reliability problem exists.

In its comments, CMP asserts that its vegetation management program is the same as BHE's program which the Commission found to be adequate. CMP states that its vegetation management staff use a matrix approach to plan the maintenance work for several years. As outage data has improved and with the implementation of the ARP, the SAIFI component is weighted more heavily, while other factors composing the matrix continue to be used to make the final selection of circuits to be worked on. The factors reviewed are overall SAIFI, tree SAIFI, total customers served on the circuit, number of tree-caused power outages, tree condition as observed by arborists in the field, power quality issues reported by CMP's customers, location of circuit from service center office, and years since last pruned. As part of its comments, CMP provided a map of one of its circuits that identified when particular areas of that circuit were last worked on.

Based on the information collected to date, it appears that CMP’s vegetation management program is not identical to BHE’s program and that CMP’s approach to vegetation management seems to be more reactive in nature than BHE’s program. We will attempt to resolve any inconsistencies between the Commission’s view of CMP’s vegetation management program based on the information we collected during this study and the information presented by CMP in its comments, in our follow-up review discussed in section IV(B)(3).

f. Inspection and Maintenance

During this investigation, our staff asked CMP to provide a copy or description of its distribution pole line inspection and treatment program. CMP stated that it did not have a formal pole line inspection program; rather it had an "informal" inspection program, which it believed complied with the NESC. According to CMP, under its informal inspection program, distribution poles and conductors are inspected by the company's line workers and meter readers during the normal course of those employees' duties. CMP could not state with certainty when, or if, any particular circuit was inspected or what work orders were generated as a result of the informal inspections. CMP stated that it performed annual infrared inspections on the polyphase portion of its distribution system.[39] CMP's polyphase circuits comprise about 21% of CMP's entire distribution system.

During the interview process, our staff expressed concern about the effectiveness of CMP's informal inspection program and expressed its belief that CMP appeared to be in violation of the NESC. In

[39] One phase of polyphase distribution plant refers to those portions of circuit where more than current is actually being carried on a structure.

December, 2004 CMP indicated that, based on its further review and participation in the Commission's investigation, it was revising its distribution line inspection program effective January, 2005. Under CMP's revised distribution line inspection procedure, CMP will be inspecting 10% of its distribution circuits in each of its service centers on a 10-year cycle. Under CMP's new program, inspection will include both a safety inspection and a plant condition inspection. The information from the inspection will be entered into a distribution inspection database.

CMP's revised inspection process is a significant improvement over its past practice and satisfies the NESC's requirement for periodic inspections. However, the Commission is concerned about the length of time that it might take CMP to inspect all of its circuits given the 10-year inspection cycle and the substantial time period during which CMP had no formal inspection process. CMP suspended its prior formal inspection program in 1999. Since CMP was on a five-year cycle at that time, it is possible that a circuit that was inspected near the beginning of the last inspection cycle will go without inspection for 20 years.[40]

In its comments to the Commission's Draft Report, CMP argues that it, in fact, has had formal inspection procedures since 1999 and that while it did modify its line inspection procedures in 1999, it never suspended its inspection activities. According to CMP, since 1999, CMP has employed a variety of inspection techniques including the following: (i) CMP annually inspects via infrared technology 100% of its 3-phase distribution system, which is equivalent to 18% of the circuit miles of the distribution system; (ii) CMP annually inspects approximately 7.5% of its circuit miles related to its ten worst performing circuits, while implementing mitigation plans for its under-performing circuits from the previous year; (iii) CMP's vegetation management team also annually inspects approximately 10% of its circuit miles and reports issues spotted; (iv) in the course of responding to outage calls, CMP inspects a portion of its circuit miles each year; (v) CMP annually checks loads and counters on every distribution recloser on nearly all of its distribution circuits and takes measurements of the electrical loads at the substation on nearly all of its distribution circuits each year; and (vi) in accordance with CMP's inspection policy (Field Operating Procedure 409), all field employees (e.g. line-workers, line inspectors, substation technicians, etc.) routinely inspect CMP's distribution equipment during the performance of their jobs, including visual roadside inspections. CMP argues that its program is thus compliant with NESC requirements.

[40] The hypothetical circuit would have been inspected in 1994 under the old program and would be inspected in 2015 under CMP's new program.

The adequacy of CMP's current inspection program in light of CMP's prior practices and the possible effect of the prior program on grid reliability will be one of the areas reviewed as part of the more detailed study to be conducted following the issuance of this Report.

g. Age of Plant

CMP's average age of its distribution plant since 1999 is depicted in Appendix F. CMP's average age of plant has generally increased since 1999. As pointed out by Liberty in its report to the Commission, age of plant alone does not indicate a worsening condition of the grid because a utility, through effective maintenance, can offset the effects that aging might have on its plant. However, the aging of CMP's plant is of some concern to us when combined with the suspension of its inspection program and fairly flat level of spending on its distribution maintenance program,.

h. Improvement Programs

CMP's overall spending levels for system improvements are established by Energy East with particular budgetary requests coming from the field. If a project request is rejected, it is sent back to its proponent, who has the option of resubmitting the request during the next cycle. CMP does not centrally track or retain records of unfunded projects.

During the interview process, CMP was asked to provide a list of circuits currently above 90% of capacity, and a list of those above 100% capacity, and for those circuits above 100% capacity, the time period that they have been above 100% capacity.[41] In its response, CMP provided a list of "2005 System Improvement Projects with Circuits Operating at 90% or Greater of Rated Capacity". *See* Appendix G. CMP has stated that it could not, beyond the list of betterment projects, identify what circuits were above 90% or 100% and how long such circuits were above such ratings. In its comments, CMP provided an updated list of the actions CMP has taken or will take on such circuits.

During the interview process CMP stated that its reliability improvement plan for its distribution system is set out in its Annual Reliability Improvement Program Report filed with the Commission as part of the Company's annual ARP filing. As part of its Report, CMP identifies its ten worst performing circuits for improvement during the upcoming year. As noted previously, at the present time the primary factor that CMP uses in determining what circuit will make its list is the circuit's contribution to the company-wide

[41] Long term exposure to overloads of designed equipment ratings will shorten equipment life resulting in equipment damage or failure causing power quality issues and interruption of service.

SAIFI metric. CMP stated during the interview that it will often go beyond the 10 circuits and work on its top 20 underperforming circuits. CMP could not, however, produce any plans or written documentation of the improvement program beyond the initial 10 circuits.

A review of CMP's annual ARP Reliability Improvement Reports demonstrates that it improved performance by taking corrective action on the circuits identified. CMP currently has 420 circuits on its system. The circuits identified annually by CMP for improvement therefore represent approximately less than 2.5% of CMP's distribution system in terms of total circuits.[42]

CMP's distribution planning record-keeping, or lack of record-keeping, is of concern to us. Specifically, it appears that CMP is not aware of the capacity or margin of safety on its circuits, or does not systematically track needed betterments which were unfunded during a particular year. This lack of record-keeping also impairs the Commission's ability to verify that CMP's circuits have adequate capacity and that CMP is taking appropriate actions to address any inadequacies. We are also concerned about the amount of time that circuits have been allowed to remain at the 100% or more loading level before the situation on such circuits was resolved through a system improvement.

Given the size of CMP's territory, we are concerned that the scope of CMP's Reliability Program appears to extend only to the circuits identified in CMP's Annual Reliability Report to the Commission. In addition, we are also concerned that by selecting the circuits to work on as part of its Reliability Improvement Program primarily based on a circuit's contribution to the overall SAIFI, CMP may be sacrificing service quality in less densely populated areas as a means of ensuring that the overall ARP targets are met. <u>We believe that these concerns can best be addressed through the more detailed review which will be conducted in the upcoming months as discussed below.</u>

3. <u>Conclusions and Recommendations</u>

Based on the results of the study, all aspects of CMP's operation of its transmission system appear to be of high quality. On an overall basis, the Commission finds that CMP is maintaining its distribution system to meet the requirements of the ARP and therefore, on a system level, CMP's distribution system is adequate. However, the Commission is concerned by the disparity between CMP's worst performing circuits and its overall SAIFI and CAIDI performance, and the nature and scope of CMP's improvement program.

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[42] In its comments, CMP notes that in its 2005 Reliability Improvement, the circuits identified represented 7% of CMP's system in terms of circuits miles.

This concern is heightened by CMP's previous suspension of its distribution inspection program, the aging of CMP's plant, the increase in the number of outages, and what appears to be inadequate record-keeping in CMP's distribution planning and maintenance operations.

As noted in section III(C), CMP has now operated under an ARP for the past ten years. The Commission and CMP have come to an agreement that this is an appropriate time to further review CMP's distribution system as a means of addressing the areas of concern raised during this general review, assessing the effectiveness of the ARP's current reliability mechanism, and clarifying any areas of misunderstanding between CMP and the Commission which may have arisen as a result of the general examination conducted here. We envision that this more detailed study of CMP's system will be done on a collaborative basis and will be similar to the study that was commissioned by Maine Public Service Company and which is discussed in section IV(D)(2)(g). This more detailed study will be conducted in the coming months and will review the physical state of CMP's distribution plant as well as its distribution planning and maintenance procedures.

C. BHE

1. Transmission System

a. Overview

As a general matter, BHE’s transmission and substation systems appear to be adequately designed and maintained, and BHE's transmission-related practices are consistent with reasonable utility practices. BHE maintains clear documented standards for transmission planning and construction. BHE recently completed a 10-year transmission planning study which will serve as a blueprint for system additions and modifications.

Under BHE’s current planning criteria, its system is designed to prevent any loss of load over 50 MW for a single contingency.[43] Loss of load of 25 MW or higher as a result of a single contingency is to be restored within two hours and load loss of 25 MW or less is to be restored within 24 hours. The Liberty Report indicates that a 50 MW single contingency loss of load criterion may be too high for a utility the size of BHE (300 MW). Liberty notes that lowering the 50 MW criterion may require increased transmission looping and would improve system reliability. Because these changes would likely increase costs to the company, and ultimately its ratepayers, we will request that BHE study the issue further and provide a cost/benefit analysis of

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[43] Single contingency refers to an event that results in the loss of a single important generator source or transmission facility within a transmission system.

lowering the criterion as part of its Annual ARP Reliability Improvement Report in March 2006.

In response to the U&E Committee's request, as part of the study, we reviewed BHE's plans for increased looping in its system as a means of enhancing its reliability, particularly in Washington County. BHE's Washington County customers are supplied by a single radial feed,[44] "Line 66," which runs from the company's Rebel Hill substation outside of Bangor to the Epping substation, then on to the Washington County substation. Line 66 is for the most part located in a remote right-of-way, making access difficult and repairs time consuming, ultimately resulting in extended outages for customers served by the line. BHE has developed plans to build a new transmission line which would run from Ellsworth to Harrington and would provide looped service into Washington County. In addition, the new transmission line would address voltage issues caused by load growth in the Hancock County area. The company's preliminary estimate of the cost of this project is in the $20 million range,[45] which the company has proposed be included by ISO-NE in the overall New England transmission tariff, thereby "socializing" the costs among all New England ratepayers. The Company has indicated that the transmission enhancements in both Hancock and Washington County have begun, and from beginning to end, can be completed in five-years.

Based on our review of the information provided by BHE, it appears that BHE's proposed Ellsworth to Harrington line would improve reliability to the company's Downeast customers. We will monitor BHE's proposal as it goes through the ISO-NE project approval process. We note that in addition to BHE's proposed Ellsworth to Harrington line, BHE has begun an improvement project on Lines 66 and 67, which should independently improve reliability in Hancock and Washington Counties. b. <u>Capital and O&M Spending</u>

BHE’s transmission related capital and O&M spending since 1999 is shown in the table below.

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[44] A radial feed is a stand-alone single transmission line or distribution circuit feed into an area with no connection to an alternative source or back-up feed through the use of a tie or switching.

[45] In its comments, BHE noted that this estimate is very preliminary and that detailed estimates of permitting costs, right-of-way acquisition costs, and line and substation construction costs have not been completed.

Table X
BHE Transmission Spending Levels

Year	Plant Additions $	Operations Expenses $	Maintenance Expenses $
1999[46]	7,345,463	511,905	1,040,385
2000	3,480,779	670,473	1,187,373
2001	1,778,750	662,410	1,120,359
2002	412,614	567,968	586,283
2003	1,096,245	704,951	1,102,085

Capital spending was significantly higher in 1999 than during the remainder of the period and reflects the completion of several major transmission projects (e.g. Orrington to Ellsworth transmission line). There was a significant reduction in both capital and maintenance spending in 2002. According to BHE, this occurred because, following its merger with Emera, BHE significantly cut back on its spending programs to assess and review current practices and explore opportunities for efficiency. In 2003, spending returned to levels that are close to historical levels.

c. Vegetation Management

BHE's recent vegetation management spending and activity on its transmission lines is set forth below:

Table XI
BHE Transmission Vegetation Management Activity

Year	Acres Sprayed and Trimmed	Expenditures $
1999	1374	220,024
2000	748	302,686
2001	919	358,014
2002	0	81,000
2003	994	345,818

There was a significant reduction in vegetation management activity when, in 2002 following the BHE/Emera merger, BHE suspended its transmission line right-of-way spraying program as part of its review of all company expenses. BHE stated that in 2004, it planned to increase its spraying program in addition to conducting its regular trim and reclamation activities.

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[46] Plant additions for 1999 and 2003 were adjusted to exclude costs associated with merchant generation plant interconnections.

d. Inspection Programs

BHE inspects its transmission system right-of-ways and lines twice a year. These inspections are designed to detect problems or defects associated with poles, structures, equipment, conductors, encroachments or vegetation conditions. BHE has corrected all high priority conditions discovered during its last four years of inspections.

BHE has a formal 10-year cycle program for inspecting, testing, and treating or replacing its transmission poles. Any transmission pole that is found not to be within NESC strength requirements is scheduled for immediate replacement. Any pole that is found to be deteriorating but still adequate for service, is re-inspected in five years. BHE reported that over the past five years it has inspected and treated 50% of its transmission poles located within a right-of-way. With its ten-year inspection and treatment program, it is expected that over the next five years all remaining poles will be examined. BHE records and maintains by paper and electronic database, all inspections completed, treatment progress, and findings on its transmission system.

BHE’s transmission pole inspection process appears to be well within the requirements of the NESC. In addition, BHE's preventative maintenance practices appear reasonable and consistent with good utility practice.

2. Distribution

a. Performance Metrics

Under the terms of the BHE ARP, as originally approved by the Commission, BHE’s CAIDI benchmark was 2.13 hours per customer per year and the SAIFI benchmark was 1.43 interruptions per year. Similar to CMP's initial ARP 2000 exclusion criterion, the BHE ARP allowed BHE to exclude outages experienced by 10% or more of its customers in one of its service areas.[47]

On September 24, 2003, BHE filed a petition requesting that the Commission modify the CAIDI and SAIFI metrics. In its request, BHE claimed that the data used to establish the initial SAIFI and CAIDI baselines were flawed and that as a result of improved reporting methods, BHE was reporting an increased number outages, which under the ARP, would be perceived as a decline in reliability performance. During the course of this

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[47] For purposes of BHE's ARP SQI calculations, four service areas were identified.

proceeding, the staff also raised the issue that the initial exclusion criterion was improperly excluding a number of small outages. On April 15, 2004, the Commission issued an Order approving a stipulation entered into by BHE and the Public Advocate, and supported by our staff, that modified the SAIFI benchmark from 1.43 interruptions per year to 2.35 interruptions per year and also modified the exclusion criterion to exclude only outages experienced by 10% of the Company's customers company-wide.[48] BHE's CAIDI target was not modified as part of this process and thus remains at 2.13 hours.

In 2002, BHE's SAIFI performance, with ARP exclusions, was 1.91 and its CAIDI performance with exclusions, was 2.35, both above the ARP target levels. Under the terms of the ARP, however, SQI penalties were not applicable for BHE's performance in 2002. In 2003, BHE met the ARP target levels with a SAIFI performance of 1.41 and a CAIDI performance of 1.92, with applicable exclusions.

Table XII presents BHE's SAIFI and CAIDI performance without exclusions since 1999.

Table XII
BHE Performance Metrics Without Exclusions

Year	SAIFI	CAIDI
1999	1.23	1.86
2000	2.39	4.82
2001	1.81	2.71
2002	2.95	4.15
2003	3.73	3.55

As can be seen from the above data, SAIFI and CAIDI during the 1999-2003 time period have trended up which, on its face, would indicate a worsening level of performance. BHE has recognized this trend and provided the following response:

As seen in the above table, the increase in customers affected by outages (both pre and post exclusions) might suggest to some that the reliability of the Company's power system has worsened over time. However, the reality is that the Company implemented a new computer-based outage management system in 2001 in an effort to improve outage prediction, management and data gathering functions. This new and more automated system replaced the paper-based method used by the Company prior to this change. After an extensive study the Company concluded that the old way of

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[48] *Bangor Hydro-Electric Company, Request for Commission Investigation into BHE's ARP Service Quality Indices,* Docket No. 2003-707, Order Approving Stipulation (April 15, 2004).

gathering outage impact data tended to under report outages by failing to capture them in the first place. This finding was reported to and acknowledged by the Commission's Staff in case proceedings last fall (see record for docket 2003-706) and was a primary reason why the Company's ARP SAIFI target was changed from 1.43 to 2.35 by Stipulation agreement on April 15, 2004.

BHE's explanation appears to be correct and, at least in part, explains the higher numbers. Nonetheless, the increase in CAIDI and SAIFI numbers over the past five years warrants close monitoring.

b. Worst Performing Circuits

During the 2001-2003 time period, BHE's average SAIFI for its 15 worst performing circuits went from 4.24 in 2001 to 5.36 in 2002 and to 6.68 in 2003. BHE's single worst circuit had a SAIFI of 11.33 in 2001 and 2002 and 8.06 in 2003. (BHE's 15 worst performing SAIFI and CAIDI circuits are listed in Appendices H and I.) In its 2002 Annual Reliability Improvement Report, BHE listed 4 of these 15 circuits for improvement.[49] In 2003, 6 of the 15 circuits listed in Appendix G were identified by BHE for improvement.

While the disparity between the BHE's worst circuits and its company-wide SAIFI levels is significantly less than CMP's, the trend in BHE's numbers seems to be going in the wrong direction. While some of the growth in the worst circuit averages may be explained by BHE's better reporting, the growth in the worst circuit SAIFI average warrants monitoring during BHE's ARP and is addressed in section IV(F).

c. Outages by Cause Code

Appendix J summarizes BHE's outages during the 1999-2003 period on a pre-exclusion basis. Consistent with the SAIFI data presented above, overall outages during the time period increased by 36%. Of particular note is the increase in weather-related outages which increased by 72%. While these increases may be explained by better reporting, as discussed above, and by an increase in the number of weather-related events, the statistics warrant monitoring by the Commission.

d. Vegetation Management

In the past, BHE utilized a seven-year distribution vegetation management cycle for its distribution circuits. In 2002, BHE elected to go to a customized trimming program that identified sections to be trimmed

[49] In its comments, BHE noted that it did include a list of the individual circuit SAIFI and CAIDI performance with its 2002 Annual Reliability Improvement Report but did not sort the list by performance.

based on an evaluation of predicted tree growth done during BHE's inspection program. As shown in Table XIII, since 1999 BHE spending on vegetation management has declined by approximately 40%. However, during the same period BHE's actual trimming activities increased by almost 45%.

Table XIII
BHE DISTRIBUTION VEGETATION MANAGEMENT PROGRAM

Year	Expenditures	Circuit Miles Trimmed
1999	$1,638,138	612.8
2000	$1,793,104	540.8
2001	$1,873,892	596.0
2002	$1,880,800	1120.6
2003	$1,252,019	1159.4

The above data would seem to confirm BHE's claim that its new customized vegetation management program is much more cost-effective than its previous approach, and that through its customized program the company has been able to enhance reliability while at the same time reducing costs.

e. <u>Capital and O&M Spending</u>

BHE's capital and operations and maintenance spending levels since 1999 are provided in Table XIV below.

Table XIV
BHE DISTRIBUTION CAPITAL AND O&M SPENDING

Year	Plant Additions $	Operations Expense $	Maintenance Expense $
1999	8,073,941	4,802,139	7,773,318
2000	7,076,374	4,986,063	8,149,991
2001	9,888,158	5,119,606	8,246,324
2002	7,700,240	4,362,881	6,537094
2003	9,777,527	3,717,911	5,480,890

BHE's distribution capital spending has generally grown during the period and does not raise any concerns. BHE's operations and maintenance expense spending have declined since BHE's merger with Emera. Taken in isolation, these reductions would be a source of concern. However, as evidenced by the operation of its vegetation management program and its Reliability Recovery Program discussed in section IV(C)(2)(g), it appears that BHE has been able to achieve these reductions while at the same time improving the operation of its distribution system.

f. Age of Plant

The average age of BHE's distribution plant is set forth in Table XV. The data does not seem to indicate any general aging of plant and is not a cause of concern at this time.

Table XV
BHE Age of Distribution Plant

Year	2000	2001	2002	2003
Distribution Poles	22.01	22.75	22.91	22.40
Distribution Conductors	30.42	31.19	31.93	33.00
Distribution Transformers	19.09	18.13	20.76	20.50
Distribution Reclosers	14.21	14.68	15.68	11.00
Distribution Regulators	17.40	21.01	22.01	19.60

g. Inspection and Improvement Programs

BHE inspects each of its distribution substations monthly. Corrective maintenance items are recorded in BHE's comprehensive computerized data management system, which allows engineers and managers to manage company resources better. In 2003, BHE completed 100% of its identified and scheduled maintenance work on its distribution system. BHE's substation and distribution equipment testing and routine maintenance programs appear to be adequate.

BHE had no formal distribution line or pole inspection program prior to 2002. Instead, BHE relied on division personnel's first hand knowledge of problems and conditions of the system. Line crews were assigned to chosen circuits to perform any corrective action or repairs they deemed necessary. Line superintendents and area managers typically inspected the circuits to determine where any system improvements were needed to replace poles, conductors or associated hardware. There was no formal process to track or record any findings, results of inspections, or completion rates. Consequently, although the Commission did not review BHE's inspection process at the time, it is likely that we would have found such a program not to comply with NESC codes as required by the Commission had we conducted such a review.

In August of 2002, BHE implemented a distribution circuit inspection program as part of its new Reliability Recovery Program (RRP).

The program consisted of a visual inspection of the distribution plant and vegetation encroachment on 10 selected circuits. These inspections were completed to prioritize any required improvements along with vegetation management needs. BHE increased the number of circuits under the RRP in 2003 by 20, bringing the total circuits inspected and targeted for improvement to 30. In 2004, the number of circuits was again increased by an additional 20. Therefore, by the end of 2004 a total of 50 circuits, out of the company's 179 circuits, had been visually inspected by foot or vehicle patrols and all vegetation management abnormalities or imminent hazards due to plant or equipment condition were recorded as part of such inspections.[50]

At the beginning of the RRP, BHE did not inspect every segment of the target circuit. BHE believed that at the initial stage of the program it was important to concentrate on inspecting the segments with higher customer density and inferior performance. However, BHE has affirmed that, starting in 2004, each circuit will be inspected in its entirety. BHE has built an application into its Geographical Information System (GIS) that will assist the inspection program in maintaining adequate records, tracking defects and recording results, as well as assisting its engineers in analyzing and prioritizing the data. Vegetation management work generated from the inspection process is printed on GIS based trim maps indicating the segments identified and approved for trim.

While BHE's revised inspection process appeared to meet most of the NESC requirements for inspections by providing a thorough inspection mechanism along with a process for retaining data, during the interview process, the staff and Liberty indicated to BHE that the revised plan still appeared to fall short of NESC's requirement that a plan for periodic testing be established to ensure that the company's plant meets all required strength codes. BHE acknowledged that its process was mostly reactive in that it was based on historical reliability performance, and that it should develop a program that was more proactive.

In February, 2005, BHE submitted a new comprehensive inspection program. Under the terms of its new program:

- Distribution circuits will be inspected every six years.

- Distribution line segments serving more than 1000 customers will be designated as "special consideration" and inspected every three years.

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[50] BHE noted in its comments that while the 50 circuits inspected under the RRP represented only 28% of the total number of circuits, the circuits inspected serve almost 60% of BHE's customers and cover over 60% of BHE's territory in terms of circuit miles.

- An unknown quantity of distribution and transmission lines will be inspected annually based upon poor performance. A pre-established procedure that takes into account a distribution or transmission circuit's percent change in SAIFI (this year compared to last), 3-year SAIFI trend and SAIFI performance for the current review period was developed by Planners and will be used to identify assets that require further outage data analysis and field examination.

- Transmission lines located in right-of-ways (ROW) will be inspected once every five years. (Note: This activity is in addition to the Company's regular annual helicopter patrols and groundline inspection and treatment program of poles in right-of-ways.)

- Transmission lines located along roads with a distribution circuit underneath will be inspected once every six years and at the same time as its adjacent distribution circuit is examined.

- Transmission lines located along roads without a distribution circuit underneath will be inspected once every six years and at the same time that the closest distribution circuit is examined.[51]

- Transmission and distribution spans crossing highways, interstates and rivers will be inspected once every three years.

BHE's new program appears to take a much more proactive approach to the inspection process and also appears to satisfy the NESC's requirement for periodic testing. The Commission will monitor BHE's performance under the new program to ensure compliance with NESC requirements.

3. Conclusions and Recommendations

On an overall basis, we have not found any "red flags" that indicate that BHE's service quality has degraded under the ARP or as a result of the BHE/Emera merger. We find that BHE management's approach to decreasing costs while actively and systematically attempting to improve service quality appears to be reasonable and effective. While BHE's SAIFI and CAIDI performance numbers have increased recently, much of this increase appears to

[51] In its comments filed with the Commission on April 11, 2005, BHE stated that, after reviewing the suggestions made on pages 7 and 18 of the Liberty Consulting Group Report that the company should consider separating its roadside transmission plant from its distribution plant when conducting its reliability programs, BHE has decided to designate all roadside transmission plant as special consideration lines which will be inspected every three years instead of every six years.

be related to improved reporting systems. Going forward, BHE, through its aggressive Reliability Recovery Program and improved inspection programs, should be able to meet its ARP targets on a company-wide basis and improve performance on the company's worst circuits. BHE's new inspection program appears to be a significant improvement over past practices and appears to meet NESC's requirements for periodic testing .

D. MPS

1. Transmission System

a. Overview

MPS is not directly tied to New England's transmission system or part of the ISO-NE region. Instead, northern Maine and MPS, electrically speaking, are part of the Canadian Maritimes region, which also includes the electric loads and generation of New Brunswick, Nova Scotia and Prince Edward Island. The transmission system in the northern Maine region is administered by the Northern Maine Independent System Administrator (NMISA).

Pursuant to the requirements of 35-A M.R.S.A. § 3204, MPS sold its generating assets to WPS in April 1999. Since that time, WPS has continued to own and operate those facilities. MPS remains a party to a power contract with Wheelabrator-Sherman, an 18 MW biomass plant located in MPS's service territory, which expires at the end of 2006. System reliability, capacity adequacy, and market competitiveness in northern Maine have arisen as issues following the passage of the Electric Industry Restructuring Act and MPS's divestiture of its generation assets.

In 2002, we opened an inquiry to obtain information about the adequacy of existing market structures, rules and laws in light of the number of supplier/generation participants in the region.[52] During 2003, the Legislature enacted Resolve 2003, ch. 5, Resolve Regarding the Reduction of Barriers to the Transmission of Electricity, which directed the Commission to work with the government of New Brunswick to study ways to reduce costs and barriers to the flow of electricity between Maine and Atlantic Canada. As part of our inquiry, and in response to the Legislature's study resolve, we met with and sought the input of the stakeholders in the northern Maine market. During this process, several approaches were suggested on the issues of whether there is sufficient generation on the northern Maine system and whether the physical interconnections with New Brunswick are sufficient to provide northern Maine with the energy needed to provide system reliability. The construction of a second tie-line between the ISO-NE system in Maine and New Brunswick,

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[52] *Public Utilities Commission, Inquiry into the Status of the Competitive Market in Northern Maine*, Docket No. 2002-82.

increasing the amount of generation with northern Maine, and increasing the strength of the transmission links between northern Maine and New Brunswick were suggested.

In our 2003 Electric Restructuring report to the Legislature on this matter, we concluded:

> In light of the new standard offer for MPS, most customers in Northern Maine are largely protected from market failures through December of 2006. This provides, in our view, a degree of "breathing space" to enable the Commission and the parties to work through the options described above. It may not be coincidental that at least some of the projects (e.g. the tie line and some of the generation projects) are targeted to come on line roughly during that period which also coincides with the termination of the supply contract with Wheelabrator-Sherman. The Commission approach in the near term, therefore, is to continue to meet with the relevant parties (including through annual or even more frequent meetings in Northern Maine or New Brunswick) to review their progress, while ensuring that the regulatory processes that may be necessary to bring helpful projects to fruition are conducted expeditiously. We expect, in the near future, filings relating both to generation projects in Northern Maine and the second tie line (and/or upgrades to the existing MEPCO line).

Subsequently, during the past calendar year, the Commission has received filings requesting approval to construct an additional tie-line between MPS's service territory and New Brunswick, the subject of Docket No. 2004-538; a request from BHE to construct a second tie-line between New Brunswick and the New England-ISO system, the subject of Docket No. 2004-771; and proposals from MPS and Eastern Maine Electric Cooperative to purchase reservations on the proposed second New Brunswick tie-line, the subject of Docket Nos. 2004-775 and 2005-17. In addition, as part of the proceedings in Docket No. 2004-538, Loring Bio-Energy, LLC (LBE), the developer of a 55 MW combined-cycle natural gas power plant to be located at the Loring Commerce Center in Limestone, Maine, filed a request that the Commission issue an order requiring MPS to execute a purchase power agreement with LBE as a means of addressing both the reliability and market issues in Northern Maine.

As we noted in a recent order denying a request for an emergency rulemaking proposal submitted by LBE, we believe the Commission, through these various proceedings, has the appropriate vehicles to address northern Maine reliability and market issues to the extent that such issues in fact exist.[53] Thus, these issues have not been included as part of this Report. We have, however, reviewed MPS's general operation and maintenance of its transmission system and address these issues below.

b. Spending Levels

MPS's spending for transmission the 1999-2003 period is presented below.

Table XVI
MPS Transmission Spending

Year	Capital Plant $	Operations $	Maintenance $
1999	1,624,684	359,652	505,772
2000	474,193	590,329	392,700
2001	1,516,075	581,705	588,005
2002	1,445,066	643,281	400,152
2003	299,175	732,772	233,923

In 2003, MPS significantly reduced transmission capital and maintenance spending. MPS stated that such reductions were temporary because of significant financial constraints at the time and that spending would be restored to normal levels in 2004 and beyond.[54] We will monitor MPS's performance to ensure any past and possible future cutbacks in spending do not result in unacceptable levels of reliability.

c. Inspection Programs

From 1999 to 2003, MPS used contractors to perform a five-year cycle inspection that included testing and treatment of its pole plant. Documentation provided during the study, demonstrated that MPS has routinely been completing the inspections and treatment programs along with all repairs and replacements identified through the inspection process. In 2003, MPS began using in-house crews for this work. Recognizing the need to undertake a more comprehensive process, MPS elected to engage in a very aggressive plan to inspect its entire transmission system within two years.

MPS inspects its transmission substations on a bi-monthly basis documenting all equipment conditions for review by engineering and management. Based on this information, MPS schedules any necessary

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[53] *Loring Bio-Energy, LLC, Request for Emergency Rulemaking to Amend chapter 301,* Docket No. 2004-793, Order Denying Request for Emergency Rulemaking (Jan. 21, 2005).

[54] MPS requested and was, in part, granted a rate increase in the fall of 2003 in *Maine Public Service Company, Request for Approval of Alternative Rate Plan,* Docket No. 2003-85, Order Approving Stipulation (Part One), (Sept. 3, 2003).

repairs. MPS also conducts infra-red inspections on all substation and transmission connections and switches.

MPS's transmission inspection programs appear to meet NESC requirements and ensure reasonable reliability of its transmission and substation systems.

d. Vegetation Management

MPS has a five-year vegetation management cycle program for most of its transmission system. MPS also follows a five-year cycle on its roadside transmission plant except in areas where easements cannot be secured or where a more frequent program is necessary because of clearance inadequacy. This process may be resulting in tree-connected problems within the areas for which MPS cannot obtain required clearances. MPS should more actively pursue securing the required easements to help eliminate this condition.

MPS's transmission related vegetation management spending and activity since 1999 are provided in Table XVII.

Table XVII
MPS Transmission Vegetation Management Activity

Year	Spending $	Right of Way Acres Treated
1999	$231,750	1,072
2000	$143,098	575
2001	$178,953	919
2002	$137,471	608
2003	-0-	-0-
2004	$123,237	852

MPS's spending and vegetation management activity in 2004 are consistent with the company's statements that it intended to restore spending and activity to historic levels after 2003.

2. Distribution System

a. Performance Metrics

Although MPS is not operating under an ARP, it nonetheless tracks its SAIFI and CAIDI performance, which is shown since 1999, without exclusions, in Table XVIII below.

Table XVIII
MPS SAIFI and CAIDI

Year	SAIFI	CAIDI
1999	1.51	1.21
2000	2.79	1.24
2001	2.05	1.19
2002	2.11	1.05
2003	2.52	1.85

MPS's performance metrics generally compare quite favorably with the two other larger utilities in the state (CMP and BHE). However, both the CAIDI and SAIFI metrics increased significantly in 2003, which warrants further monitoring.

b. Worst Performing Circuits

MPS's ten worst performing circuits for the past three years in terms of SAIFI and CAIDI are presented in Appendix K. The average for these 10 worst performing circuits over the three-year period is presented in Table XIX below.

Table XIX
MPS Worst Performing Circuits

Year	SAIFI	CAIDI
2001	4.63	3.89
2002	7.18	2.67
2003	5.66	5.66

The above information shows significantly less disparity between MPS's overall SAIFI and CAIDI and its worst performing circuits than we observed for both CMP and (to a lesser extent) BHE.

c. Outage by Cause Code

MPS's outage by cause code information is presented in Appendix L. MPS's equipment related outages have increased steadily from 17 in 1999 to 101 in 2004. During that same time period, MPS's weather related outages have also steadily increased. This increase in outages may reflect the equipment issues which were raised in the recent report by MPS's consultant and issues surrounding MPS's prior vegetation management program which apparently have been addressed by the company. *See* sections IV(D)(2)(f) and IV(D)(2)(h).

d. Distribution Spending

MPS's spending levels on distribution plant and operations and maintenance for the years 1999 through 2003 are presented in Table XX. Plant additions during this time period have grown significantly and apparently reflect the company's catching up on deferred capital improvements. *See* section IV(D)(2)(h). Operations and maintenance expenses have been fairly consistent over the time period and do not raise any major concerns.

Table XX
MPS Distribution Spending

Year	**Plant Additions $**	**Operations Expenses $**	**Maintenance Expenses $**
1999	$2,239,340	$696,659	$1,453,888
2000	$2,474,765	$860,238	$1,375,444
2001	$2,903,365	$715,954	$1,537,548
2002	$3,991,750	$751,631	$1,538,220
2003	$3,404,661	$804,423	$1,343,582

e. Age of Plant

MPS's average age of its distribution plant, as of July 1, 2004, is presented in Table XXI.

Table XXI
MPS AVG. AGE OF DISTRIBUTION PLANT-IN-SERVICE
(In Years)

Distribution Plant-In-Service	7-1-04
Poles	33.5
Conductors	33.5
Sub Transformers	28.0
Line Transformers	30.0
Reclosers	18.1
Regulators	15.5

MPS could not produce records of the average of plant for prior years so we cannot draw any conclusions regarding trends. In comparison with the other investor-owned utilities, MPS's pole plant age appears to be significantly higher, which raises some concern about the condition of MPS's distribution plant. *See* Appendix M.

f. Vegetation Management

MPS's past trimming program for its distribution system appeared to be reactive and geared towards attacking “hot spots”.[55] The line clearance maintenance plan utilized from 1999 to 2002 assigned and prioritized circuits based on two factors: 1) distribution line clearances completed; and 2) outage statistics compiled by a technical services engineer.

In 2003, MPS reevaluated and redesigned its vegetation management program to place greater emphasis on prevention and cost-effectiveness. A significant change was MPS's decision to use in-house vegetation management crews and equipment. MPS determined that it could achieve more flexibility by using its own line crews to perform vegetation management work in combination with routine line construction work, maintenance and trouble-shooting. MPS's goal is to track circuit clearance inadequacies through the inspection process and to institute a five-year cycle for trimming on its distribution circuits.

MPS's spending on its distribution vegetation management program is set forth in Table XXII.

Table XXII
MPS Distribution Vegetation Management

Year	Budgeted Amount	Expenditure
1999	$574,000	$556,834
2000	$470,000	$472,906
2001	$560,500	$554,092
2002	$540,000	$475,694
2003	$481,575	$415,059

The reductions in 2003 expenditures reflect savings realized from MPS's revised vegetation management program. MPS does not track its distribution vegetation management by miles worked or spans worked, so we cannot assess the cost-effectiveness of MPS's new program.

g. Inspection Programs

Distribution line and pole inspections from 1999 to 2003 were performed pursuant to MPS's five-year Distribution Circuit Improvement Plan funded through the capital budget. MPS Area Managers managed this plan by assigning line personnel to inspection patrols during off-peak construction periods of the year. Based on an internally generated investigation done by an outside firm, *see* section IV(D)(2)(h), MPS recognized

[55] Trees identified as either burning or within 4 feet of conductors on circuits that were considered as critical or worst performing.

the need to develop a more detailed and formal inspection program with better reporting capabilities for its distribution utility inspection process.

Starting in 2003, MPS instituted a more detailed and formal distribution line pole inspection process that uses an asset management system. Pole plant age, the type of product and treatment, and outage history performance determine the circuits selected and scheduled for inspection. Under this new process, primary distribution poles are all sounded with a hammer to detect any potential hollow areas, rot or loose shell that would compromise the integrity and strength of the structure. Poles are then evaluated and classified for required action. All information collected in the field is recorded in a computer database.

At this point, MPS has not determined whether it will use either a three-year or five-year cycle standard for its new distribution inspection program. However, at least initially, MPS expects to complete a full inspection within a three-year period, after which it will evaluate which cycle length to adopt.

MPS's new inspection process is a significant improvement over past practice and should assist it in analyzing and managing its plant condition and also produce greater overall reliability. The adoption of more formal record keeping has allowed MPS to track the work identified through the inspection process better. During 2003, approximately 90% of the work identified through the inspection process was completed or was the subject of a work order. MPS's new inspection plan appears to be in compliance with the NESC.

h. <u>Improvement Programs</u>

In 2002, MPS retained the firm of R.W. Beck, Inc. (Beck) to assess the condition and performance of MPS’s system, the adequacy of projected budgets for capital improvements and system maintenance and the organizational infrastructure to support the system. Beck’s report (the Beck Study) was issued in May 2003. In its review, Beck provided the following findings regarding MPS’s system:

- Overall, transmission lines and poles appear to be in good condition and reasonably maintained. On a relative basis, some of the lines are older but still in good condition with the exception of some of the oldest pole lines and areas where woodpecker damage is a problem. A significant number of lines may require higher maintenance cost in the future due to age, type, and life expectancy.

- Climbing inspections are not currently part of MPS's transmission maintenance program. Climbing inspections should be done on a five-year cycle to ensure that the condition of crossarms and pole tops are known.

- Thermal (infrared) aerial or ground inspections should be scheduled during the yearly ground pole inspections; this would result in a five-year cycle to cover the transmission facilities.

- All of the substations were visited and were classified to be in poor, poor-fair, fair, or good condition. Individual assessments ranged from poor to good. On average, MPS substation facilities are in poor-fair condition, primarily due to the age of transformers. MPS's Substation Priority Report seems to adequately capture problem areas that need correction; however, MPS needs to develop a mechanism to ensure corrective action is taken in a timely manner.

- A significant number of possible NESC code violations were observed at many substation sites. It is recommended that all code violations be given the highest attention and priority in correcting.

- There are many miles of older three-phase distribution lines that are in poor condition and will require attention in the immediate future.

- Urban distribution facilities are generally in poor to very poor condition and require a higher priority to upgrade.

- Rural distribution facilities are generally in good condition except for older 12.5 kV lines and single phase lines.

- Single-phase rural facilities reviewed were found to be in poor condition.

- Implementing a right-of-way or vegetation management program for the distribution line is a critical component to maintain reliability. A three to five year cycle to cover the distribution system is recommended.

Based on these findings, the Beck Study made the following conclusions and recommendations:

- System planning must be improved to reflect current industry planning practices including developing an engineering model, coordinated development of planning methodology and assumptions, and evaluation of alternatives based on sound cost/benefit economic analysis.

- Application of new technology within the organization is minimal. Technology solutions that result in increased efficiencies and cost savings in customer care, purchasing, material handling, operations, maintenance, and construction, should be sought.

- System reliability for the distribution system in certain areas may be at risk. Implementation of a more aggressive distribution right-of-way or vegetation management program, as well as upgrades to certain urban systems in high load density areas, are critical.

- The reliability of the transmission system may be at risk because a climbing inspection to inspect the condition of the pole top and crossarms is not used. The inspection program needs improvement.

As confirmed during the course of investigation, MPS has already addressed the immediate safety issues raised by the Beck Study, and has also adopted many of the recommendations of Beck with regards to its inspection and maintenance programs. While the findings and conclusions contained in the Beck Study were not all positive, MPS's initiation of the Beck Study and its response thus far are commendable. The Beck Study's objective assessment provides MPS with an excellent blueprint for future improvements in system reliability.

4. Conclusions and Recommendations

Several criteria we examined during the course of this investigation (i.e. increase in equipment outages, increase in tree-related outages, age of plant) raised questions about the direction of the reliability of MPS's distribution system. MPS, through its initiation of the Beck Study and its subsequent follow-through, appears to have acknowledged the problem and appears to be taking appropriate steps to address the issues. For example, MPS has adopted improved vegetation management and inspection programs that should enhance the reliability of its system over time.

E. EMEC

Please see pages 24-27 of the Liberty Report.

F. Overall Findings and Recommendations

Based on the available information, the Commission believes that alternative rate plans (ARPs) have not, to date, compromised the overall reliability of the grid in Maine. However, CMP and, to a lesser extent, BHE have perhaps been influenced by the operation of the ARPs' Service Quality Index penalty mechanism, by focusing on meeting the overall company-wide targets to the detriment of service in the utilities' less densely populated areas. It appears that BHE, through its reliability recovery program, should be able to ensure that service to all of its circuits is reasonable and adequate. A closer look at CMP's grid will be necessary using an approach similar to the Beck Study recently carried out by MPS. The Commission and CMP have agreed to conduct such a study on a collaborative basis.

On a going-forward basis, the Commission will monitor the performance of both BHE and CMP in less densely populated areas to ensure that service issues in such areas are being appropriately addressed. In addition, at the time we next consider a Alternative Rate Plan proposal for a utility, we will direct the parties to address the issue of reliability of service in the subject utility's less densely populated areas and will strongly consider how the Commission can ensure adequate service to such areas.

The Commission will also take additional steps to keep itself apprised of the utilities' inspection programs. None of the subject utilities' inspection programs was, at least until recently, in full compliance with the NESC. During the coming months, the Commission will monitor the inspection programs of each of the subject utilities. The Commission may also establish a mechanism, either through an amendment to the Commission's rules or annual reporting requirements, which will ensure that the Commission has sufficient current information about all utilities' inspection practices.

V. BULK POWER SYSTEM OPERATION

A. Operational Overview

The operation of the bulk power supply system in New England is primarily the responsibility of ISO-NE in coordination with local control centers (LCCs) and generators. This section of the study outlines the current operational status of the New England regional grid, and the procedures designed to address abnormal grid conditions that could occur under extraordinary circumstances.

1. Status

Regional demand for electric power peaks during the summer season in New England, due primarily to air conditioning loads. In past years, the regional bulk power grids that provide electric power to Maine consumers have experienced very tight supply conditions during peak hours in the summer months. In the summer of 2004, however, supplies were sufficient to meet demand.

For winter 2004-2005, NERC concluded that on a national level, "generating and transmission resources will be adequate to meet the demand for electricity." NERC identified as a problem, however, "the potential for curtailment of natural gas supplies for electric generation" during cold weather periods, "particularly in ERCOT [Texas] and New England":

Natural gas supply and delivery is a growing concern in New England during the winter. Although natural gas supplies within New England are projected to be adequate during winter 2004/2005, extreme weather can impact the regional supply and delivery infrastructures. As New England experienced during the January 14-16, 2004, cold snap, extreme winter weather can drive up demand for natural gas. This increase in demand caused an abnormal number of gas units to report gas and unit availability problems. If this occurs in New England during the upcoming winter, emergency operating procedures may be needed to remediate any possible deficiencies. [56]

Steps being taken to address this situation are described in a subsequent section of this Report.

In contrast to the rest of the New England bulk power system, Maine's demand for electric power has typically peaked during the winter season, when the regional grid is less stressed than during the summer season. In addition, Maine has more than enough in-state generation capacity for the state's needs which, when coupled with transmission limits on exports, tends to place Maine in a better position than other New England states in terms of reliability as well as price. For example, Maine's peak load was approximately 1,900 MW this past summer, when about 3,600 MW of generation capacity was available within the State's borders, and at times some of this generation was not available to the rest of the region because of transmission constraints. This past winter, supplies were adequate to meet regional demand.

ISO-NE communicates regularly with power generators, transmission owners, brokers, electric distribution companies, and state and federal government officials on regional power system conditions. During peak periods, the New England Governors' Conference coordinates weekly conference calls among the ISOs in New England and New York, the Northeast Gas Association, Department of Energy, representatives of all New England state governments, and other organizations as appropriate, to provide updated status information on regional energy situation developments. Representatives of the Maine PUC and State Planning Office routinely participate in those briefings. When the regional system is stressed, other procedures and communications mechanisms are also employed, as described in the following three sections.

2. Capacity Deficiency

When available supplies are not expected to meet forecast demand, the ISO-NE implements pre-existing procedures to maintain the

[56] "2004/2005 Winter Assessment – Reliability of the Bulk Electricity Supply in North America," NERC, November 2004

reliability of the regional power grid. These include: ISO-NE Operating Procedure 4 (OP4), ISO-NE Operating Procedure 7 (OP7), and ISO-NE Operating Procedure 6 (OP6). The procedures would normally be implemented in that sequence, although under certain circumstances portions of all of the procedures could be implemented simultaneously without advance notice.

OP4 includes separate actions that dispatch all available generation, curtail service to interruptible consumers, reduce voltage, share operating reserves, purchase emergency power from resources outside of New England, and make public appeals for voluntary conservation. Utilities in New England experience various low-level OP4 actions almost every year.

Maine is better situated than other parts of the region from the perspective of the bulk power supply system. Because under tight power supply situations, the transmission lines connecting Maine's generators to the rest of the region are often filled to capacity, Maine would not likely have the same power problems as other parts of New England. Capacity warnings and curtailment requests are generally implemented only where they are beneficial to the overall system. Accordingly, ISO-NE typically exempts Maine from most OP4 declarations.

If a power shortage or emergency were to occur on the New England grid due to unforeseen circumstances, Maine government (including the Governor's Office, Maine Emergency Management Agency, and the PUC) would receive alerts regarding the status of the electric system from the ISO-NE and CMP. Due to local circumstances elsewhere in the region, ISO-NE could be faced with implementing OP4 measures in some areas of New England where the bulk power supply system may be less robust than in Maine. In that event, ISO-NE media advisories would clearly state the areas affected by OP4 advisories, and those areas that would be exempt. The same exemption would typically apply to ISO-NE implementation of OP7.

In OP7, utilities are directed to interrupt power to blocks of consumers, and the utilities may implement these interruptions in a rotation to minimize the effect of the interruption to any single group of consumers ("rotating blackouts"). The customers interrupted are designated by distribution circuit, and include residential, commercial, and industrial consumers. At this time, no priority is given to any specific class of consumers, although utility rotating blackout plans attempt to move highly-critical facilities such as hospitals to the end of the rotation list. New England has never experienced a system-wide rotating blackout situation.

OP6 would reflect a widespread electric system blackout, where utilities stabilize and restore the power grid. Large portions of the power grid could experience extended outages for several hours, and depending on local conditions, perhaps longer.

Further details about these ISO-NE operating procedures are contained in Appendix N.

C. Recent Bulk Power System Events

1. Northeast System Blackout, August 2003

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power system blackout. The blackout began in Ohio a few minutes after 4:00 pm Eastern Daylight Savings Time and, over a period of about eight minutes, spread across the Midwest, New York, Ontario, and into parts of New England. Although most of New England and the Maritimes avoided a blackout by separating from the rest of the Northeast, voltages were depressed across portions of New England and some large customers (including one in Maine) disconnected from the grid automatically.

An ISO-NE report of the event describes the regional impact as follows:[57]

> The effects on Massachusetts were confined to small areas in Springfield and the Berkshires, which are directly connected to New York, where the power disturbance had serious impacts. In the rest of New England, the effects were confined primarily to southwest Connecticut and northwest Vermont, which have been identified as weaker links in the New England bulk power system.
>
> Most of New England escaped from a potentially devastating impact due to a number of factors:
>
> - Automatic relays that appropriately shut down "the border" between New York and New England, effectively shielding us from the cascade effect;
> - The work of system operators to stabilize the system and keep the lights on;
> - A healthy supply of generation resources that enabled New England to produce enough power to be self-sufficient once the region was isolated from the rest of the Eastern Interconnection,...; and
> - Close coordination between ISO New England and local utilities to restore power as quickly as possible in the affected areas.

[57] "Blackout 2003 – Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout," ISO-NE, February, 2004.

The outage affected an area with an estimated population of 50 million people and 61,800 MW of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey, and the Canadian province of Ontario. Power was not restored for four days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion. In Canada, where gross domestic product was down 0.7% that month, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down C$2.3 billion. During the event, the New England system remained largely intact as a result of the New England system's design, communications, and ISO-NE operating procedures. A review of the event by NPCC found that "the restoration process following the unprecedented loss of load on August 14th was effectively and successfully carried out by system operators well trained to cope with such an event."[58]

The August 14 blackout challenged NERC and the electric power supply industry to demonstrate that established reliability standards are unambiguous and measurable, and that they are being properly followed. As described earlier in this report, compliance with NERC standards and guidelines is voluntary on the part of industry participants. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 found that improvement was needed in that area, and stated in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards." In response, on April 14, 2004, FERC issued an order including a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable." Accordingly, NERC decided to accelerate the transition from existing operating policies and planning standards to a single set of reliability standards under a process accredited by the American National Standards Institute (ANSI).[59]

On February 8, 2005, NERC adopted a comprehensive set of reliability standards for the bulk electric system. The new reliability standards incorporate existing NERC operating policies, planning standards, and compliance requirements into an integrated and comprehensive set of measurable reliability standards. The new standards, which apply to all entities

[58] "Restoration of the NPCC Areas Following the Power System Collapse of August 14, 2003," NPCC Inter-Control Area Restoration Coordination Working Group (CO-11), 2004.

[59] http://www.nerc.com/~filez/standards/Version-0.html

that play a role in maintaining the reliability of the bulk electric system in the United States and Canada, took effect on April 1, 2005. NERC has expressed concern, however, that federal legislation is needed to make compliance with reliability standards mandatory, but to date Congress has not taken action on such legislation.[60]

In response to the August 14, 2003 blackout, NERC committed to take other immediate actions to strengthen the reliability of the North American bulk electric system. Specifically, NERC created readiness audit teams and tasked them with assessing the degree to which individual Control Areas and Reliability Councils have met their responsibilities. The NERC audit team reviewed ISO-NE practices in May 2004, and identified several improvements that ISO-NE could make to internal systems and processes, but found that ISO-NE had adequately addressed reliability issues overall:

The New England region has tightly integrated reliability requirements into the design of the wholesale electricity market. This has led to a consistent set of market rules and operating procedures that prescribe the way the market operates and clearly identifies the responsibilities and obligations of all market participants. Having the reliability requirements clearly identified allows ISO-NE to focus on reliability issues and to ensure that the market can operate efficiently in all timeframes. The New England market approach, with its reliability-first philosophy, has led ISO-NE staff to develop a strong and well-developed culture of reliability. Everyone the audit team interviewed exhibited the reliability-first philosophy. [61]

The U.S./Canada Power System Outage Task Force final report on the blackout found that operator performance was an important root cause of the blackout. FERC noted that failures included "lack of situational awareness, failure of personnel to declare an emergency, and failure to take appropriate action" to keep the bulk electric system stable. On December 15, 2004, FERC directed power grid operators and transmission providers to report back to that commission on their training practices. FERC plans to analyze the results of that survey, and submit a report to Congress on the issue.

FERC also noted that reactive power[62] issues contributed to the August 2003 blackout. In December 2004, FERC staff presented a report to

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[60] Statement by Dave Hilt, NERC Vice President, Compliance, NERC Regulatory Webcast Briefing, October 28, 2004.

[61] "Control Area Readiness Audit Report -ISO New England," NERC, July 29, 2004.

[62] Reactive power supports the voltages that must be controlled for system reliability. Sources of reactive power include generators, capacitors and static

that commission on the role of reactive power in establishing reliable power systems. In this ongoing inquiry, FERC held a technical conference on March 8, 2005, and is soliciting comments on the related FERC staff report.

In summary, NERC and its regional reliability councils have taken positive action in response to the August 14, 2003 regional blackout. NERC reliability standards recently adopted using ANSI processes took effect in April 2005, and upgraded NERC cyber security[63] standards will follow. While it appears that these standards will have a beneficial effect on the reliability of the bulk power system, because compliance with them is voluntary at this time, it is premature to conclude that these actions will provide all necessary reliability improvements identified in the wake of the 2003 blackout. The Commission will continue to participate in the standards review process and to monitor the degree of reliability provided by regional utilities.

2. New England Cold Snap, January 2004

Maine is in a better position than other parts of the region because of ample generation and import capacity, and transmission constraints between Maine and the rest of New England. As a consequence, ISO-NE generally excludes Maine from capacity deficiency declarations unless there is a capacity deficiency in Maine. One exception to that practice occurred in mid-January 2004.

The coldest winter period in the New England region in 25 years and very high demand for electricity, combined with tight conditions in the natural gas markets, stressed the region's bulk power system.[64] Despite a record winter peak electricity demand of 22,818 MW, numerous unexpected generator outages, and projected capacity deficiencies, ISO-NE was able to avoid interruptions of electrical supply. A unique set of circumstances resulted in ISO-NE requests to satellite control centers, including the Maine dispatch facility at CMP, "to prepare contingency plans in anticipation of NOP 4 and possible NOP 7 actions." Atypically, Maine was not excluded from that ISO-NE advisory.

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var compensators (SVCs). One market issue related to reactive power is that although such power must be generated to maintain system reliability, it is often not treated in market transactions equally with power generated for wholesale or retail sale.

[63] Cyber security relates to the actual or potential compromise of the electronic or physical security perimeter or the operation of a programmable electronic device or communications network, including hardware, software, and data, associated with bulk electric system assets.

[64] This event is described in detail in the "Final Report on Electricity Supply Conditions in New England During the January 14 – 15, 2004 'Cold Snap'," ISO-NE Market Monitoring Department, October 12, 2004.

The PUC immediately notified numerous stakeholders throughout the state, including Governor Baldacci.

Among the circumstances that affected that situation were the severe curtailment of electricity imports from New Brunswick and Québec due to low temperatures and the resulting record demand in those locations, low-temperature induced high efficiencies on transmission lines between Maine and New Hampshire thereby increasing the north-to-south flow of energy, and milder temperatures in New York that allowed New York to export additional energy to New England, mitigating the usual high north-to-south demand on those lines.

Another significant factor was the unavailability of gas-fired generation in the region. As a result of the addition of more than 9,000 MW of gas-fired combined cycle generating plant capacity in New England, the region has become more dependent on natural gas than in the past. During the January 2004 cold snap, some of New England's gas generators, including some in Maine, took advantage of high natural gas prices by curtailing generation and selling their gas back into the market. Of the 9,000 MW of generation that was unavailable to meet electric load in the region during the Cold Snap, gas fired-units were responsible for 7,000 MW.[65]

The January 2004 Cold Snap highlighted vulnerabilities of the New England bulk power system, including limitations of the natural gas pipeline network. New England's dependence on natural gas for electric power generation can cause problems during extreme winter conditions, which increase natural gas demand for both heating and electric power generation. NERC identifies this issue as "a growing concern in New England during the winter season" because extreme weather can affect supply and delivery infrastructures while driving up demand for natural gas.[66]

ISO-NE, the Northeast Gas Association, regional utilities and regulatory agencies have examined that situation and developed near-term responses. Among remedies already deployed, is a new ISO-NE Market Rule for Cold Weather Event Operations (Market Rule 1, Appendix H) to improve coordination of operations between the power generation and natural gas sectors in New England during cold weather events. A NEPOOL/ISO Cold Snap Task Force and an Electric and Gas Operating Committee have been established to address these electric-natural gas issues, and further studies have been

[65] "Cold Snap Response – Actions Taken To Protect Reliability In New England", Stephen G. Whitley, ISO-NE Senior Vice President & COO presentation to ISO-NE Fuel Diversity Working Group, November 3, 2004.

[66] "2004/2005 Winter Assessment – Reliability of the Bulk Electricity Supply in North America," NERC, November 2004.

commissioned into related factors, including assessment of dual fuel capabilities of generating units in the region.

ISO-NE, NEPOOL participants, state utility and environmental regulators, gas industry representatives, and the New England Governors' Conference Power Planning Committee have collaborated on specific remedial steps for both short-term and long-term applicability.[67] ISO-NE expects short-term actions to increase supply-side resource availability in New England by at least 2,000 MW over the capacity available during the Cold Snap. These actions include:

- Adjusting wholesale market timing to enhance generators' ability to secure scarce fuel supplies.

- Denying generator requests for economic outages during extreme winter conditions.

- Requesting plants to use alternative fuels during weather events where possible.

- Advising demand response resources to reduce consumption on notice.

- Improving communications between electric and natural gas entities.

- Closely coordinating with neighboring systems to manage power exports and imports during shortages.

Stakeholders also identified longer-term actions to improve import capabilities with neighboring systems, to develop electric market incentives to encourage more dual-fuel generating capacity in New England, and to create incentives for the use of firm-gas transportation arrangements for gas-only generating units. Maine PUC Commissioners and staff are monitoring those activities and participating in them as appropriate, and will continue to work with ISO-NE and other stakeholders.

C. Capacity Adequacy

Prior to restructuring the electric industry in the late 1990's, integrated utilities were responsible for building or contracting for enough capacity to assure that there was adequate generation to reliably supply customers' needs. Their planning criterion was to have adequate generation capacity such that the probability of disconnecting non-interruptible customers

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[67] "ISO New England's Management Response to the October 12, 2004 publication entitled *Final Report on Electricity Supply Conditions in New England during the January 14 - 16, 2004 'Cold Snap'*," ISO-NE, October 12, 2004.

due to resource deficiency, on average, would be no more than once in ten years – the “one in ten” criterion.[68]

In the restructured environment, however, firms invest in new generation when they expect it will be profitable, without regard to whether the one in ten reliability level will be achieved. Furthermore, electric restructuring resulted in the divestiture of generation from T&D utilities, and thus the T&D utilities no longer have the obligation to develop or purchase generation resources. This raises the question of whether some mechanism is needed to ensure that we will have adequate generation capacity in the restructured wholesale electric market.

When restructuring was beginning in New England, a number of firms decided to construct new, mostly natural gas-fired, facilities in Maine and throughout much of the rest of New England. As a result, the region has enjoyed surplus capacity for the past few years. The only significant reliability problems have been in areas of Connecticut and Massachusetts where the transmission system does not allow sufficient imports from elsewhere in New England and siting new generation has proved problematic. Most of the region, including Maine, has more than adequate generation to meet the installed capacity requirements in the near term.

As a result of concerns that over the coming years new investment in generation may not occur as needed to maintain reliability, there has been a long and complex proceeding before the FERC regarding whether some form of Locational Installed Capacity Market (LICAP) should be instituted to maintain existing generation capacity and attract new generation capacity in locations where the generation is needed, in time to meet future deficiencies. The Maine PUC has been very active in this case, including sponsoring the testimony of staff and outside consultant witnesses. Our position has been that some form of capacity adequacy is desirable, but that the specific proposal of ISO-NE is likely to be both expensive and ineffectual.

VI. SECURITY OF CRITICAL GRID INFRASTRUCTURE

The term “security” as used in the electric sector has at least two different meanings: NERC defines “security” as “the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.” We address these issues in a more general sense in the reliability discussions elsewhere in this report. In this section, we address the adequacy of grid security more from the perspective of the physical and cyber protection of critical grid infrastructure.

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[68] ISO-NE Planning Procedure No. 3 - Reliability Standards for the New England Area Bulk Power Supply System.

Significant sectors of the 'critical infrastructures' identified nationally for special protection fall within the Commission's intrastate jurisdiction: electric power, natural gas, telecommunications, and drinking water. Public utilities that provide those services are required by Maine law to provide safe, reasonable and adequate facilities and service.[69] To satisfy that requirement, utility facilities must be secure. Public utilities have the primary responsibility to secure their own infrastructure.

The utility industry, through NERC, NPCC, and related utility industry organizations, has identified best practices and guidelines for the security and protection of critical grid infrastructure. While compliance with those measures is voluntary on the part of industry members, since the terrorist attacks of September 11, 2001, the utility industry has strengthened those standards and provided additional incentives for industry compliance, including notification of federal and state utility regulators in the event that repeated violations of industry standards are observed in private industry security audits. Those standards include traditional security issues related to the physical protection of facilities, and are evolving to address cyber security issues as well.

Cyber security has arisen as a new challenge for the electricity sector. Utilities are increasingly reliant on computer-based Energy Management Systems (EMSs) to control their power systems, and are increasingly monitoring and operating system devices using Supervisory Control and Data Acquisition (SCADA) systems that in some circumstances could be vulnerable to outside interference, possibly through the Internet. These vulnerabilities have been recognized as a national issue. According to the U.S. General Accountability Office,[70] the control systems community faces several challenges to securing control systems against cyber threats. These challenges include: the limitations of current security technologies in securing control systems, the perception that securing control systems may not be economically justifiable, and the conflicting priorities within organizations regarding the security of control systems.[71]

ISO-NE conducts compliance and internal controls reviews of its own facilities and the local control centers (LCC)[72] in New England under a FERC-approved Transmission Operating Agreement. ISO-NE conducted reviews of the LCCs in 2004 and 2005, including a 2004 review of the LCC operated by CMP. These reviews include the security of the Energy Management System, with a

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[69] 35-A M.R.S.A. § 301(1).

[70] The U.S. General *Accountability* Office (GAO), recently changed its name from the U.S. General *Accounting* Office.

[71] "Critical Infrastructure Protection – Challenges and Efforts to Secure Control Systems," GAO-04-354, U.S. General Accountability Office, March 2004

[72] LCCs were previously known as satellite control centers.

comprehensive review of cyber security policies and procedures for electronic and physical security, personnel and training, system security management, and incident reporting and response planning. Internet vulnerability assessments were performed in 2004 at all LCCs and SCADA centers, which are the primary data centers supplying real-time information to the ISO.

NERC has issued an interim cyber security standard that addresses some of these vulnerabilities on an "Urgent Action" basis, and plans to replace that interim standard upon its expiration in August 2005 with a high-level industry-wide cyber security standard. Maine T&D utilities are currently working to comply with the interim NERC standard. As in the case of vegetation management standards and practices, however, a one-size-fits-all industry consensus standard, which may represent the lowest common denominator of industry interests, may not be the most effective method of elevating cyber security within the industry, particularly because effective enforcement mechanisms may not be in place.

While utilities have the primary responsibility to secure their own infrastructure, the Commission provides support and encouragement to utilities, and collaborates on security issues with utilities, industry organizations, federal agencies, and other state agencies such as the Maine Emergency Management Agency (MEMA) in the Department of Defense, Veterans & Emergency Management. As part of the State's homeland security planning efforts, the Commission participates on a State security team that includes the Chair of the State Homeland Security Council, MEMA's homeland security coordinator, and the officer in charge of the Maine State Police intelligence and special services unit. That team is conducting an ongoing review of utility security improvements implemented since September 2001. Those reviews are being conducted with utility security and management teams at individual utilities, beginning with a review of CMP during the summer of 2004.[73] Reviews have been initiated with BHE and MPS, with follow-up underway. The team will review security arrangements at other key utilities during the next several months. Dialogues related to issues discussed among participants continue until potential issues and concerns have been resolved to the mutual satisfaction of the participants. A principal outcome of this process is the improvement of communications among these entities related to security issues.

The Commission has exchanged 24x7 contact information with all major utilities for both operational status and security purposes to assist State and utility interests in communicating issues related to infrastructure security.

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[73] Because of the highly sensitive nature of specific security measures to protect key utility critical infrastructure and systems, this report addresses only the process undertaken by the State to review those measures, and not the specific details of actions taken by utilities or law enforcement agencies to enhance the security of that infrastructure.

Commission staff have assisted the Adjutant General, State Police, National Guard, MEMA, and emergency managers in providing alert and advisory information to utilities whose infrastructure may be threatened. In addition, the Commission has designated staff members to serve on the State's Emergency Response Team (ERT) to advise the Governor and MEMA on utility-related issues, and is developing the capability to use detailed geographic information system (GIS) maps and data about key utility infrastructure to support the Governor, MEMA, and ERT during events that involve utility systems. In addition to information forwarded to the Commission staff by MEMA, the Commission staff also receive threat advisories from DHS, the FBI, the U.S. Attorney's Office, NERC, the national Electric Sector Information Sharing and Advisory Center (ES-ISAC), and the Multi-State ISAC, to enable the Commission to support Maine utilities, law enforcement, and emergency management organizations as may be needed.

MEMA conducted a comprehensive energy emergency exercise on February 17, 2005, involving the ERT, the Governor's Office, key utilities, selected county and local governments, and other organizations. The exercise was designed to identify areas where the State may need to improve its ability to manage extreme power system emergencies. Reviews of exercise issues and lessons learned are ongoing.

On a national level, the Commission staff actively participates on a committee chartered by national utility regulators[74] to identify best practices and roles for utility regulatory commissions to protect critical infrastructure nationally. That committee works to improve communications among federal and state agencies and utilities on utility-related critical infrastructure issues, and to represent the interests of Maine and similarly-situated states in the evolution of utility-related homeland security practices by federal agencies.

In summary, Maine T&D utilities have taken positive steps to improve the security of their key infrastructure in the aftermath of the September 11, 2001 terrorist attacks and subsequent events that have attempted to challenge the integrity of the bulk power system. These improvements are ongoing, and due to the evolving nature of potential threats to critical infrastructure Maine utilities must continue to evaluate their effectiveness and ensure that protection of their key infrastructure addresses the changing environment that may pose new and different threats over time.

The Commission continues to address utility infrastructure security issues, including the following factors that make utility infrastructure security particularly challenging:

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[74] The National Association of Regulatory Utility Commissioners (NARUC) Ad Hoc Committee on Critical Infrastructure.

- Utility infrastructure is usually highly visible and thus not a hidden target.

- Utilities increasingly use modern technology, including the internet, to monitor and control their facilities, and the internet is far from secure and is accessible globally.

- High-tech approaches are increasing the interdependence among utility services.

- To minimize the inadvertent or unnecessary release of sensitive information about critical infrastructure, some Federal agencies and utilities restrict information flow to States, complicating State and local roles as the levels of government that would provide initial response to an incident that affects local infrastructure.

The Commission's goal remains that, even in times of an extreme or unanticipated emergency, utility facilities and services will continue to be safe, reasonable, and adequate to meet Maine's needs. The Commission will continue to coordinate with State homeland security, emergency management, and law enforcement personnel to monitor and support utilities' progress in these areas.